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May 26, 2006

Mary L. Cottrell, Secretary
Department of Telecommunications and Energy
One South Station, 2nd Floor
Boston, MA 02110

Re: NSTAR Electric Company, D.T.E. 06-40

Dear Ms. Cottrell:

Enclosed for filing is a $100 filing fee and an original and eight copies of the Joint Petition of Boston Edison Company ("Boston Edison"), Cambridge Electric Light Company ("Cambridge"), Canal Electric Company ("Canal") and Commonwealth Electric Company ("Commonwealth"; together, the "Companies") d/b/a NSTAR Electric for Approval of Merger ("Petition") by the Department of Telecommunications and Energy (the "Department") pursuant G.L. c. 164, § 96. This filing is made in accordance with the Department's December 30, 2005 order (the "Order") approving the Settlement Agreement (the "Settlement Agreement") in D.T.E. 05-85.

In support of the Petition, NSTAR Electric presents the testimony and exhibits of Christine L. Vaughan, Manager of Revenue Requirements.

As described in the Petition, NSTAR Electric respectfully requests that the Department:

- Determine that the proposed merger and the terms thereof are consistent with the public interest;
- Approve the proposed merger pursuant to G.L. c. 164, § 96;
- Approve the consolidation of retail rates for Basic Service and the Pension Adjustment Factor;
- Approve the ratemaking proposal relating to the reclassification of Cambridge's 13.8 kilovolt facilities as distribution facilities, with recovery of associated costs transferred from transmission to distribution rates;
- Approve NSTAR Electric's proposal to implement uniform depreciation rates that are expense neutral at the functional level;

- Confirm that Boston Edison (to be renamed NSTAR Electric Company), as the surviving corporation of the merger among and between the Companies, will continue to have all of the franchise rights and obligations that were previously held by Cambridge and Commonwealth, and that further action, pursuant to G.L. c. 164, § 21, is not required to consummate the merger; and

- Issue such other and further orders as may be necessary and appropriate.

In order to complete necessary financial actions and implement changes to the accounting systems for a January 2, 2007 merger date, NSTAR Electric requests that the Department complete its review, and issue an order by September 1, 2006.

Thank you for your attention to this matter. Please do not hesitate to contact me should you have any questions.

Very truly yours,

Robert N. Werlin

Robert N. Werlin

cc: Service List, D.T.E. 05-85

COMMONWEALTH OF MASSACHUSETTS

DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

Boston Edison Company, Cambridge Electric Light Company, Canal Electric Company and Commonwealth Electric Company d/b/a NSTAR Electric	)	D.T.E. 06-40

JOINT PETITION OF BOSTON EDISON COMPANY, CAMBRIDGE ELECTRIC LIGHT COMPANY, CANAL ELECTRIC COMPANY AND COMMONWEALTH ELECTRIC COMPANY d/b/a NSTAR ELECTRIC FOR APPROVAL OF MERGER

Now come Boston Edison Company ("Boston Edison"), Cambridge Electric Light Company ("Cambridge"), Canal Electric Company ("Canal") and Commonwealth Electric Company ("Commonwealth"; together, the "Companies"), and respectfully move that the Department of Telecommunications and Energy (the "Department") approve, pursuant to G.L. c. 164, § 96, the proposed merger among and between the Companies to create a single electric company, NSTAR Electric Company ("NSTAR Electric"). In addition, the Companies request that the Department confirm that Boston Edison, to be renamed NSTAR Electric Company, as the surviving corporation of the merger, will retain all the franchise rights and obligations that were previously held by each of the Companies and that further action, pursuant to G.L. c. 164, § 21, is not required to consummate the merger.

In support thereof, the Companies state the following:

1. Boston Edison is a Massachusetts electric company, pursuant to G.L. c. 164, § 1, with a principal place of business in Boston, Massachusetts.

2. Cambridge is a Massachusetts electric company, pursuant to G.L. c. 164, § 1, with a principal place of business in Boston, Massachusetts.

3. Commonwealth is a Massachusetts electric company, pursuant to G.L. c. 164, § 1, with a principal place of business in Boston, Massachusetts.

4. Canal is a Massachusetts electric company, pursuant to G.L. c. 164, § 1, with a principal place of business in Boston, Massachusetts.

5. The Companies have entered into an Agreement and Plan of Merger dated April 10, 2006 (the "Merger Agreement"), which is subject to necessary approvals of government regulatory authorities having jurisdiction, providing for the merger of the Companies into Boston Edison. As a result of the Merger Agreement, Cambridge, Commonwealth and Canal will combine with and into Boston Edison, which will then change its corporate name to NSTAR Electric. A copy of the Merger Agreement is provided as Exhibit NSTAR-CLV-2, an attachment to the testimony of Christine L. Vaughan, Manager of Revenue Requirements for the regulated operating companies of NSTAR (Exhibit NSTAR-CLV-1).

6. The Companies' proposal satisfies the statutory public-interest standard set forth in G.L. c. 164, § 96, as applied by the Department in recent proceedings. Eastern-Colonial Acquisition, D.T.E. 98-128 (1999); Eastern-Essex Acquisition, D.T.E. 98-27 (1998); NIPSCO-Bay State Acquisition, D.T.E. 98-31 (1998); Boston Edison/Commonwealth Energy System Merger, D.T.E. 99-19 (1999). Those cases established a "no net harm" standard for evaluating proposed mergers. Eastern-Colonial Acquisition, D.T.E. 98-128, at 5; Eastern-Essex Acquisition, D.T.E. 98-27, at 8. Specifically, the petitioners must show that there is an "avoidance of public harm" or that the "public interest would be at least as well served by approval of a proposal as by its denial." Boston Edison/Commonwealth Energy System Merger, D.T.E. 99-19, at 10.

7. The proposed merger will require approval from the Department, pursuant to G.L. c. 164, § 96, as well as approval from the Federal Energy Regulatory Commission ("FERC").

Because G.L. c. 164, § 21 limits the transfer of utility franchises, it is necessary and appropriate for the Department, in approving the merger, to confirm and to ratify that all of the franchise rights and obligations currently held by Cambridge and Commonwealth continue with Boston Edison and thereafter with NSTAR Electric upon the consummation of the merger. See Boston Edison/Commonwealth Energy System Merger, D.T.E. 99-19, at 108 (1999).

8. In D.T.E. 99-19, the Department already determined that the merger of BEC Energy and Commonwealth Energy System that created NSTAR was in the public interest because it created significant public benefits beyond the "no net harm" minimum standard. Boston Edison/Commonwealth Energy System Merger, D.T.E. 99-19, at 84. The currently proposed merger of the Companies is appropriate at this time because they have reached the point where, to move forward and complete the final stages of merger-related consolidation activities, it is necessary to serve electric customers as a single, integrated electric company.

9. As a result of the proposed merger of the Companies, and by operation of law, the following will occur:

(a) The facilities, properties and other rights, assets, franchises and liabilities will vest in Boston Edison.

(b) The debt of Cambridge and Commonwealth will be retired.

(c) NSTAR will cancel its common equity shares in Cambridge, Commonwealth and Canal and those three companies will cease to exist.

(d) Boston Edison will be the sole surviving corporate entity and will change its corporate name to NSTAR Electric, either upon the consummation of the transaction or thereafter.

(e) NSTAR Electric will consolidate retail rates for Default ("Basic") Service, the Pension Adjustment Factor and for Transmission Service.

10. By virtue of the merger and without any action on the part of any holder of any capital stock of the Companies, each share of Cambridge common stock, Commonwealth common stock and Canal common stock issued and outstanding immediately prior to the merger will be converted into one share of common stock of Boston Edison.

11. After receipt of the necessary regulatory approvals, on January 2, 2007, Cambridge, Commonwealth and Canal will be merged with and into Boston Edison in accordance with the laws of the Commonwealth of Massachusetts. Boston Edison will be the surviving corporation in the merger and will continue its corporate existence under the laws of the Commonwealth of Massachusetts. Boston Edison will subsequently be renamed NSTAR Electric.

12. In addition, as approved by the Department, the Settlement Agreement executed in the rate case proceeding of Boston Edison, Cambridge, Commonwealth and NSTAR Gas Company in D.T.E. 05-85, imposes additional requirements regarding the merger of the Companies. According to the Settlement Agreement, the proposed merger will require a multi-step process involving phased rate-design changes. Specifically, the Settlement Agreement contemplates that NSTAR Electric Company will be established by the Companies on January 2, 2007 (Settlement Agreement at ¶ 2.16). Also under the Settlement Agreement, the merged NSTAR Electric will maintain separate distribution rates and transition charges for customers in the existing service territories of Boston Edison, Cambridge and Commonwealth until at least January 1, 2010 (Settlement Agreement at ¶ 2.17).

13. The Settlement Agreement also provides for the consolidation of transmission rates and the reclassification of Cambridge's 13.8 kilovolt ("kV") facilities as distribution facilities,

with recovery of associated costs transferred from transmission to distribution rates (Settlement Agreement at ¶ 2.18). The ratemaking proposal for the transfer is described in Exhibit NSTAR-CLV-1, at 20-29, and Exhibit NSTAR-CLV-6 through Exhibit NSTAR-CLV-8.

14. The Settlement Agreement also permits NSTAR Electric to implement "uniform depreciation rates that are expense neutral at the functional level…" (Settlement Agreement at ¶ 2.6.2). NSTAR Electric's proposal for such depreciation rates is described in Exhibit NSTAR-CLV-1, at 29-32, and Exhibit NSTAR-CLV-9 through Exhibit NSTAR-CLV-11.

15. The testimony and supporting exhibits of Christine L. Vaughan, Manager of Revenue Requirements for the regulated operating companies of NSTAR explains in detail the proposed transaction, and is attached hereto as Exhibit NSTAR-CLV-1.

16. It is necessary, expedient and in the public interest for the Merger Agreement to be approved by the Department in order to provide long-term advantages to the Companies, their shareholders, customers and employees.

WHEREFORE, the Companies respectfully request that the Department:

a. Determine that the proposed merger and the terms thereof are consistent with the public interest;

b. Approve the proposed merger pursuant to G.L. c. 164, § 96;

c. Approve the consolidation of retail rates for Basic Service and the Pension Adjustment Factor;

d. Approve the ratemaking proposal relating to the reclassification of Cambridge's 13.8 kV facilities as distribution facilities, with recovery of associated costs transferred from transmission to distribution rates;

e. Approve NSTAR Electric's proposal to implement uniform depreciation rates that are expense neutral at the functional level;

f. Confirm that Boston Edison (to be renamed NSTAR Electric Company), as the surviving corporation of the merger among and between the Companies, will continue to have all of the franchise rights and obligations that were previously held by Cambridge and Commonwealth, and that further action, pursuant to G.L. c. 164, § 21, is not required to consummate the merger; and

g. Issue such other and further orders as may be necessary and appropriate.

Respectfully submitted,

BOSTON EDISON COMPANY,
CAMBRIDGE ELECTRIC LIGHT COMPANY
COMMONWEALTH ELECTRIC COMPANY
CANAL ELECTRIC COMPANY

By their attorneys,

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Dated: May 26, 2006

BOSTON EDISON COMPANY
CAMBRIDGE ELECTRIC LIGHT COMPANY
CANAL ELECTRIC COMPANY
COMMONWEALTH ELECTRIC COMPANY
d/b/a NSTAR ELECTRIC

Exhibit NSTAR-CLV-1

D.T.E. 06-40

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Christine L. Vaughan. My business address is One NSTAR Way, Westwood, Massachusetts, 02090.

Q. Ms. Vaughan, by whom are you employed and in what capacity?

A. I am Manager of Revenue Requirements for NSTAR Electric & Gas Corporation. In this capacity, I am responsible for all regulatory filings concerning the financial requirements of its affiliates, Boston Edison Company ("Boston Edison"), Cambridge Electric Light Company ("Cambridge"), Canal Electric Company ("Canal"), Commonwealth Electric Company ("Commonwealth") and NSTAR Gas Company ("NSTAR Gas").

Q. Please summarize your educational background.

A. I graduated from McGill University in Montreal, Canada in 1990 with a Bachelor of Engineering Degree and from Yale University in 1998 with a Masters Degree in Business Administration. Additionally, I have earned the right to use the Chartered Financial Analyst designation.

Q. Please describe your present responsibilities.

A. I was hired as Manager of Revenue Requirements on July 19, 2004. In this role, I am responsible for directing the preparation of financial data required for rate case filings and serve as a revenue-requirement witness. My responsibilities currently include, among a variety of other financial services, the reconciliation of transition and transmission charges and the Pension Adjustment Factor and other regulatory and revenue-requirement matters.

Q. Please summarize your business experience.

A. Before working at NSTAR, I worked as a management consultant for five years at Arthur D. Little and at Charles River Associates, a company that purchased a portion of Arthur D. Little. In this capacity, I assisted clients with financial issues such as acquisition support and asset privatization. I also helped clients develop long-range strategic plans and assisted them with market analysis. Prior to my consulting experience and my MBA, I worked for six years at DuPont and BASF as a development engineer.

Q. Have you previously testified before any regulatory body?

A. Yes. I am currently sponsoring testimony before the Department of Telecommunications and Energy (the “Department”) in D.T.E. 05-89, the reconciliation filing of Cambridge and Commonwealth, D.T.E. 05-88, the reconciliation filing for Boston Edison, and for NSTAR’s Pension Adjustment Factor in D.T.E. 05-90. I have also testified before the Department in various other proceedings including prior reconciliation cases and have presented testimony in D.T.E. 05-85 in support of the rate case Settlement Agreement. As described below, that Settlement Agreement contemplates the merger which is discussed in this testimony. In addition, I also testified in D.T.E. 04-65, a proceeding initiated by the City of Cambridge relative to the purchase price applicable to Cambridge's streetlights. At the federal level, I offered testimony at the Federal Energy Regulatory Commission ("FERC") in Docket Nos. ER05-69-000 and ER06-427-000 on behalf of Boston Edison.

II. OVERVIEW

Q. What is the purpose of your testimony?

A. The purpose of my testimony is: (a) to describe the merger of Cambridge, Canal and Commonwealth into Boston Edison (together, "NSTAR Electric"); (b) to demonstrate that the merger meets the applicable statutory standard, as applied by the Department; (c) to describe the reasons for, and the ratemaking impact of, reclassifying Cambridge's 13.8 kilovolt ("kV") facilities from transmission to distribution when the companies merge; and (d) to explain the method of setting new uniform depreciation rates that are expense neutral at the functional group level at the time of consolidating the rates.

Q. Please describe the merger.

A. As set forth in the Agreement and Plan of Merger included as Exhibit NSTAR-CLV-2, the merger, itself, is a relatively simple transaction. The transaction will consist of a merger under Massachusetts law, whereby each of Cambridge, Commonwealth and Canal will combine with and into Boston Edison. As a result of the merger, and by operation of the law, the facilities, properties and other rights, assets, franchises and liabilities will vest in Boston Edison. The debt of Cambridge and Commonwealth will be retired. The common stock of Cambridge, Commonwealth and Canal will be converted into common stock of Boston Edison, all of which will be owned by NSTAR, and those three companies will cease to exist. Boston Edison will be the sole surviving corporate entity, and plans to change its corporate name to NSTAR Electric Company, either upon the consummation of the transaction or thereafter.

Q. What regulatory approvals are required?

A. The merger request requires approval of the Department and FERC. Department approval is required under G.L. c. 164, § 96, and is the subject of this case. Exhibit NSTAR-CLV-3 is a copy of the FERC petition for the application of the NSTAR electric operating companies under Section 203 of the Federal Power Act to merge and consolidate their facilities into Boston Edison.

Q. Is NSTAR Electric requesting Department approval of the transfer of the utility franchises of Commonwealth and Cambridge to Boston Edison?

A. Yes. It is my understanding, on advice of counsel, that because G.L. c. 164, § 21 limits the transfer of utility franchises, it is appropriate and necessary for the Department, in approving the merger, to confirm and to ratify that all the franchise rights and obligations currently held by Cambridge and Commonwealth continue with Boston Edison (as renamed NSTAR Electric Company) after the consummation of the merger. This would be the same ratification and confirmation that the Department provided in D.T.E. 99-19, page 108.

III. THE MERGER'S CONSISTENCY WITH THE PUBLIC INTEREST

Q. Does the merger comply with the public-interest standard of G.L. c. 164, § 96, as applied by the Department?

A. Yes, the merger meets the public-interest standard as applied in the Department's decisions in Eastern-Essex Acquisition, D.T.E. 98-27, NIPSCO-Bay State Acquisition, D.T.E. 98-31 and Boston Edison/Commonwealth Energy System Merger, D.T.E. 99-19 (1999). It is my understanding that, in those cases, the Department stated that the public-interest standard requires merger proponents to demonstrate that "no net harm" will result from the transaction with regard to customer interests. The Department described this standard as an "avoidance of harm to the public" or that the "public interest would be at least as well served by approval of a proposal as by its denial." D.T.E. 99-19, at 10.

In those cases, the Department also confirmed that it would consider a number of factors in determining whether the "no net harm" test has been met, including:

- Impact on rates;
- Impact on quality of service;
- Savings resulting from the merger;

- Impact on competition;
- Financial integrity of post-merger entity;
- Fairness of the distribution of benefits resulting from the merger between stockholders and customers;
- Societal costs and benefits of the merger;
- Impact on economic development; and
- Alternatives to the merger.

I will address each of these factors in my testimony.

Q. Why is NSTAR Electric seeking a merger of the electric companies at this time?

A. From an organizational perspective, NSTAR Electric has reached the point where it needs to move forward to complete the final stages of its merger-related consolidation activities in order to serve electric customers as a single (integrated) electric company. Currently, NSTAR Electric operates as a single, integrated system. However, NSTAR's three electric companies exist as separate legal entities, with customers of each company served under differing rate structures and rate tariffs. To complete the consolidation of operations made possible by the NSTAR merger and to capture remaining efficiencies, NSTAR Electric needs to move forward to integrate these corporate structures into a single unit.

Q. Why didn't NSTAR merge the retail electric companies when NSTAR was created?

A. At the time, the focus was on completing the merger in the least possible time in order to minimize the stress on employees and to avoid unnecessary uncertainties in the market. Moreover, there were several legal and practical impediments (Transcript VIII at 1047, 1052 [D.T.E. 99-19]). This was especially difficult in 1999 because electric industry restructuring required prescribed rate reductions, which expired only last year.

Q. Please be more specific regarding NSTAR Electric's objective of completing the consolidation of the electric companies.

A. With the merger of BEC Energy and Commonwealth Energy System and the Department's approval of the merger-related rate plan in D.T.E. 99-19, NSTAR embarked on a multi-phase plan to achieve the complete consolidation of the legacy utility systems. In this vision, utility operations would be fully integrated over a number of years with customers of the unified system ultimately taking service under common rate structures and rate tariffs. In the past six years, NSTAR has successfully implemented the initial stages of its consolidation plan with substantial benefits inuring to the benefit of customers.

NSTAR Electric avoided distribution rate increases resulting from inflationary increases and other cost pressures because of its ability to capture cost savings through consolidation and integration of the utility operations following the merger. In approving the merger-related rate plan filing, the Department found that NSTAR had demonstrated projected total savings of more than $630 million in the ten years following the merger (2000-2009) (D.T.E. 99-19, at 73). In D.T.E. 04-2 (2004), the Department accepted NSTAR's Merger Savings Report finding that it demonstrated savings of approximately $314 million in just the first three years following the merger (i.e., through 2002). This means that, rather than achieving the projected annual savings of approximately $63 million (on average), NSTAR achieved average annual savings of more than $100 million.

Therefore, the merger has presented an unparalleled opportunity to benefit customers through substantial and permanent reductions in operating expenses. These reductions include non-pension administrative and general costs, which have declined considerably since the last adjudicated base-rate proceedings of the NSTAR operating companies, and direct distribution operations and maintenance expense, which have increased by a much lower percentage in the same time period as compared to an increase in the CPI. The future level of revenues for NSTAR Electric distribution service was resolved by the Settlement Agreement approved by the Department in D.T.E. 05-85. However, NSTAR recognizes that the full promise of the mergers will not be realized until the electric companies are fully integrated, including, eventually, a unified rate structure and common tariffs. In accordance with the terms of the Settlement Agreement, this final step cannot be accomplished immediately and will require a multi-year process involving phased rate-design changes.

Q. What terms of the Settlement Agreement in D.T.E. 05-85 directly affect the merger of NSTAR Electric?

A. Paragraph 2.16 of the Department-approved Settlement Agreement in D.T.E. 05-85 contemplates that a single corporate entity, NSTAR Electric Company, will be established by the merger of Cambridge, Commonwealth and Canal with and into Boston Edison on January 2, 2007. The Settlement Agreement provides that the merger may be accomplished by the implementation of an agreement and plan of merger and after other appropriate Department approvals and formal petitions approved by FERC. The Settlement Agreement also provides that the merged NSTAR Electric will maintain separate distribution rates and transition charges for customers in the existing service territories of Boston Edison, Cambridge and Commonwealth until at least January 1, 2010 (Settlement Agreement at ¶ 2.17). Another provision of the Settlement Agreement relating to the merger specifies the consolidation of transmission rates and the ratemaking treatment of Cambridge's 13.8 kV facilities (Settlement Agreement at ¶ 2.18).

Q. Could you address how the merger meets the statutory "no net harm" test applied by the Department?

A. Yes. As described above, this merger is the final structural/corporate step in the merger that created NSTAR. The Department has already reviewed the major impacts of merging the companies, thus, for this intra-company consolidation of NSTAR Electric, the remaining impacts generally reviewed by the Department in merger cases are not material. In fact, the vast majority of the costs and benefits of the NSTAR merger were considered by the Department in D.T.E. 99-19, in which the Department determined that the merger was in the public interest because it created significant customer benefits (well beyond the minimum "no net harm" standard) (D.T.E. 99-19, at 84). In this merger of NSTAR Electric, there are no significant, net impacts on competition, economic development, societal costs and benefits, the allocation of benefits and costs between customers and shareholders, or service quality. By combining the companies, there is expected to be some minor efficiency gains or strengthening of NSTAR Electric's financial integrity that can be achieved over time through the consolidation of accounting functions and financial instruments. Although the bulk of the operational savings were accomplished by combining the work force, there are small efficiency savings in reducing the number of separate accounts to be maintained, reconciling and auditing separate legal entities and reducing the number of regulatory filings, which will facilitate regulatory oversight. For example, in the future, the Department will have to review only two rate filings to cover the NSTAR electric and gas distribution companies rather than the four that were included in D.T.E. 05-85. Because operations have already been consolidated, the remaining net overall cost savings impact of the merger will be minimal. However, the same considerations that led the Department to approve the earlier NSTAR merger in D.T.E. 99-19 support the implementation of this further step in this proceeding.

Q. How is NSTAR Electric proposing to account for the call premiums incurred by Commonwealth and Cambridge in connection with the extinguishment of its long term debt?

A. NSTAR Electric proposes to follow the accounting guidance promulgated in General Instructions No. 17 of the FERC Uniform System of Accounts. Since Boston Edison issued $200 million of 30-year debentures in the first quarter of 2006 in anticipation of financing the recall of Commonwealth and Cambridge's debt, NSTAR Electric is proposing to amortize the call premiums over the remaining life of the new debt. Therefore, this amortization will be recognized ratably over the period in which the interest savings will be realized.

Q. How will the merger of Boston Edison, Cambridge and Commonwealth affect retail rates?

A. Under the terms of the Settlement Agreement at paragraph 2.17, NSTAR Electric is required to maintain separate distribution and transition rates for the three service territories through January 1, 2010. Thus, these rates will not be affected at this time by merging the companies. Any future proposal to consolidate distribution and/or transition rates after this date would require Department review and approval.

However, the consolidation of other rate elements is possible under the terms of the Settlement Agreement, and NSTAR Electric proposes to consolidate those rates beginning January 1, 2007, as a first step in the simplification of rates under a merged NSTAR Electric Company.

IV. RETAIL RATE CONSOLIDATION

Q. What rates will be consolidated under the NSTAR Electric merger in 2007?

A. NSTAR Electric proposes to consolidate retail rates for Default ("Basic") Service, the Pension Adjustment Factor and retail Transmission Service. The consolidation will help the Department, the Attorney General and NSTAR Electric minimize the administrative burden of maintaining separate schedules, analyses and filings for what is essentially one operating company. In addition, it will be simpler for customers to understand rates and rate changes by providing single unified rates. Because the aggregate level of rates will be no higher than if separate rates (and separate corporate entities) were maintained for Boston Edison, Cambridge and Commonwealth, there is no net harm from the consolidation.

Q. Will NSTAR Electric's process of obtaining supplies for Basic Service for their customers change?

A. Only to the extent that there will be solicitations for one company rather than for three. Solicitations will be performed in accordance with the Department's directives, as modified by the Settlement Agreement for residential customers (Settlement Agreement at ¶ 2.21). After the issuance of a request for proposals, the Basic Service contracts are awarded to the winning bidder(s) from the competitive market with the lowest price in each load zone and customer class. This will not change. The only difference is that the suppliers will contract with NSTAR Electric instead of the separate companies.

Q. What is the impact on each of the operating companies resulting from the consolidation of the rates for Basic Service?

A. In accordance with Department requirements, supplies for Basic Service are procured on a rate class and load-zone basis. The Cambridge service territory is located entirely in the Northeast Massachusetts load zone ("NEMA"), the Commonwealth service territory is located entirely in the Southeast Massachusetts load zone ("SEMA") and Boston Edison's service territory is located predominately within NEMA and partially in SEMA. In setting retail Basic Service rates for Boston Edison, separate NEMA and SEMA rates are offered to large commercial and industrial customers, but a blended rate is offered to residential and small commercial customers. After the merger, NSTAR Electric will operate in the two zones (NEMA and SEMA), just as Boston Edison does, and the consolidated entity will follow the same Department-mandated rate procedures currently in effect for Boston Edison. That is, large commercial and industrial customers will receive separate NEMA or SEMA rates, based on the customer's location. So these customers should not see any change with the merger. Residential and small commercial customers throughout the merged NSTAR Electric service territory will receive blended rates.

Q. Won't this change affect the rates paid by residential and small commercial customers?

A. Not in the aggregate, but there may be some difference between the blended NEMA and SEMA rate and the individual component rates. The difference in the costs between the NEMA and SEMA load zones is relatively small and, with the new 345 kV transmission upgrades to be completed this year by Boston Edison, this differential is expected to be minimal and declining in the future. An analysis of the real-time locational marginal pricing on a monthly, load-weighted basis was performed for the historical calendar years 2004 and 2005 for the NEMA and SEMA regions and is shown in Exhibit NSTAR-CLV-4. On an average, 12-monthly-load-weighted basis, NEMA's prices were higher than the SEMA's prices by only 1.5 percent and 3.7 percent, for the years 2004 and 2005, respectively. A key reason for the differential is the existence of transmission constraints in the NEMA region. This differential in pricing of power supplies between the two regions should decline considerably when Boston Edison's new 345 kV line is placed in service in mid-year 2006.

Q. How will the new 345 kV line reduce the price differential between NEMA and SEMA?

A. The new 345 kV line from Stoughton to Boston will substantially increase the transmission capacity of the integrated network system in the NEMA zone, including the Greater Boston area, thereby reducing the transmission congestion constraints of importing power into NEMA.

Q. What is the impact to the three operating companies from the consolidation of the pension adjustment factor?

A. Although there are separate pension adjustment factors ("PAF") for the three companies, the underlying pension and post-retirement benefits are corporatewide expenses that are allocated to the companies in the annual PAF filing. After the merger of NSTAR Electric, there would be no reason to continue to allocate costs among customers of the three electric companies, and the only allocation would be between NSTAR Electric and NSTAR Gas.

Q. Is there any impact on rates from the consolidation of the pension adjustment factor?

A. Not in the aggregate, so the consolidated impact would meet the "no net harm" standard. However, there would be a small impact on the individual rates for customers of the three operating companies. For example, in 2006, the PAF for Boston Edison is $0.00030 per kilowatt-hour ("kWh"), for Cambridge is $0.00086 per kWh and for Commonwealth is $0.00080 per kWh. If a single PAF were established for a merged NSTAR Electric in 2006, the PAF would have been $0.00045 per kWh. Thus, the PAFs for Cambridge and Commonwealth customers would have been slightly lower and the PAF for Boston Edison would have been slightly higher. The increase in the average residential, non-heating bill for Boston Edison customers would have been less than 8 cents per month, or less than 0.1 percent.

Q. What is the benefit to customers of consolidating of the pension adjustment factor?

A. Again, the existence of one unified rate for customers makes for easier understanding of the rates and easier communication with customers. In addition, the lower cost of administration for NSTAR Electric and the Department provides for future benefits.

Q. What is the impact to the three companies resulting from the consolidation of the transmission costs?

A. The transmission costs incurred by each company reflect the transmission investment costs and expenses that are assessed under the various FERC-approved rates and tariffs. The FERC-approved rates and tariffs consist of regional as well as localized costs, and are a passthrough to retail customers on a load basis. The regional costs are composed of: (1) Regional Network Service costs; (2) Scheduling and Dispatch costs; (3) Congestion Management costs; (4) System Restoration and Planning costs; (5) REMVEC costs; (6) VAR support; and (7) NEPOOL administration costs. The local costs consist of: (1) Local Network Service costs and (2) Local Scheduling and Dispatch costs.

Q. How will the merger affect local transmission tariffs?

A. When the three electric utilities – Commonwealth, Cambridge and Canal – consolidate into Boston Edison, Boston Edison's existing local FERC transmission tariff will be the surviving FERC-approved transmission tariff on file at FERC and effective under the provisions of the Federal Power Act. Since the existing FERC local transmission tariffs are formula rates with very similar provisions, once the assets and expenses are consolidated, the cost impact will be minimal, and therefore, the impact meets the "no net harm" standard. As described below, Cambridge's transmission tariff includes 13.8 kV facilities, which will require a reclassification of those facilities and an adjustment in the recovery of the corresponding costs.

Q. What is the effect on the regional transmission costs for each company resulting from the consolidation of the companies?

A. With respect to the Regional Network Service ("RNS") costs that ISO-NE bills to the companies under the ISO-NE Tariff, there will be minimal cost impacts once the assets and expenses have been combined. There is only one RNS formula rate under the ISO-NE Tariff that is applicable to all users of Pool Transmission Facilities ("PTF"). As such, NSTAR Electric's RNS revenue requirement associated with providing service over PTF facilities will be calculated on the same basis as that which was done on an individual-company basis. As for the other regional costs, there would be very minimal regional cost shifting resulting from the consolidation, since the other regional costs, except for congestion management, are currently socialized among all the transmission providers on a network load basis.

Q. What are the congestion management costs, and are there cost impacts because of the consolidation of these costs?

A. The congestion management costs that are recovered through transmission rates are attributed to Reliability Must Run ("RMR") and Special Constrained Resources ("SCR") costs. The RMR costs within the New England Control Area are determined for each of the various established load zones and then socialized within each load zone on a network load basis to all the companies within the load zone. The SCR costs are charged specifically to the company that requires the SCR for local reliability purposes. It is difficult to ascertain if there are any cost impacts going forward because of the uncertainty as to the life expectancy of the RMR agreements that are in effect today. Many of the RMR agreements have termination provisions that will be exercised once an installed capacity ("ICAP") mechanism is recognized as fully implemented. It is still unclear at this juncture when ICAP will begin, but once it does, the majority of the RMR costs that are being charged today as congestion costs are expected to cease. As for SCR costs, while each company incurs these charges at various times, Cambridge has incurred the majority of the SCR costs, based upon the use of the Mirant Kendall Generating Station. When load is completely transferred to the new East Cambridge Substation in Cambridge later in 2006, Cambridge will no longer be reliant on this internal generation for providing local system support. Because of the uncertainty of the future amount of congestion costs that will be recoverable under transmission rates, congestion management costs cannot be used as a long-term factor in establishing cost effects in merging the transmission costs of all three companies into NSTAR Electric.

Q. Once the Companies merge into a single NSTAR Electric, will NSTAR Electric incur different congestion costs over the different zones in which it operates?

A. Yes, the merged NSTAR Electric will operate over the NEMA and SEMA load zones, but it will socialize the effects of congestion costs across the two zones. NSTAR Electric will follow the present practice of Boston Edison by consolidating the effects of different congestion costs over two load zones and charge its customers the average costs of congestion. This practice is also being followed by National Grid for its customers.

Q. What is the actual impact of consolidating the retail transmission rates for all three companies?

A. Exhibit NSTAR-CLV-5 sets forth the retail transmission costs for all the three companies and on a consolidated basis. The retail transmission costs reflect actual 2005 costs and were adjusted to exclude congestion costs and the over/under collection costs from the previous year since those are a one-time occurrence and reconciliation. The consolidated LNS revenue requirements were calculated according to the surviving Boston Edison LNS tariff, with adjustments to existing data, where necessary, to reflect a combined company. Most significant of these adjustments are: (1) the effect of adopting Boston Edison transmission depreciation rates for assets originally owned by Cambridge and Commonwealth, thus reducing depreciation expense to be recovered; (2) eliminating inter-company support expenses and revenues; (3) reclassifying costs among FERC accounts reflecting consistent accounting practices once the

Companies are combined; and (4) adopting an assumed capital structure for the combined companies of 55 percent common equity rather than the approximate 62 percent common equity that would result if the current capital structures were simply added together. Cambridge's transmission costs also exclude the 13.8 kV-related costs to account for the transfer of the recovery of those costs in distribution rates. As demonstrated by Exhibit NSTAR-CLV-5, consolidation will result in a net reduction in total transmission rates to customers. There is a slight increase of 1.4 percent for transmission customers of Commonwealth, and customers of Boston Edison and Cambridge see a reduction of 2.9 percent and 21.0 percent, respectively, in the transmission portion of their bill.[1] Thus, the projected net impact on transmission rates of consolidating the companies produces net benefits to customers.

V. TRANSFER OF CAMBRIDGE 13.8 kV FACILITIES FROM TRANSMISSION TO DISTRIBUTION

Q. What is the rationale for the transfer of Cambridge's 13.8 kV costs from transmission to distribution?

A. Costs relating to Cambridge's 13.8 kV facilities are currently included in transmission rates rather than in distribution rates. This is unusual, and reflects the operational characteristics of Cambridge's system that existed a decade ago. Since that time, additions to Cambridge's system, specifically the addition of 115 kV lines and a new substation, combined with the resulting changes in

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[1] This analysis is based on 2005 costs and the elimination of the impact of congestion charges.

operational practices of the 13.8 kV system, have changed the dynamics of the system. The 13.8 kV facilities changed from an integrated 13.8 kV transmission network to a distribution system that provides power to local load. The Department-approved Settlement Agreement provides that, upon the consummation of the merger of NSTAR Electric, "Cambridge's 13.8 kV facilities shall be reclassified as distribution facilities and recovered in distribution rates…" (Settlement Agreement at ¶ 2.18).

Q. Please explain why Cambridge's 13.8 kV system was classified as transmission facilities.

A. The primary reason for designating facilities as transmission is that they interconnect generation sources and provide an efficient means of delivering the power to local load centers. In 1997, when Cambridge last obtained approval for classifying its 13.8 kV system as transmission (D.P.U./D.T.E. 97-93), the Kendall Generating Station located in Cambridge had interconnection ties via 13.8 kV circuits through Cambridge's major substations that also connected to Boston Edison's tie-line facilities. This assured that generation could flow to major load centers in the City of Cambridge, even if there was not enough external power flowing over Boston Edison's bulk tie-line facilities into Cambridge' territory. Thus, Cambridge's 13.8 kV system of substations and circuits was integral in providing the transmission of power to its local load centers at that time. However, with the recent completion of the East Cambridge Substation, Cambridge is no longer reliant on the Kendall Generation Station for servicing any of the load requirements of its customers. As such, facility changes have occurred where the Kendall Generating Station is now interconnected to the Cambridge system through a 115 kV line to its new East Cambridge Substation and through a second 115 kV line to its Putnam Substation. Power is now transmitted to Cambridge's system and to the New England grid through Cambridge's 115 kV lines and interconnecting substation switching facilities, instead of through Cambridge's 13.8 kV lines and 13.8 kV substations. Thus, the function of the 13.8 kV system has shifted from a transmission system to a more typical distribution system, where its function is to supply power to local distribution customers.

Q. Are there any standard tests that establish the functional category of transmission and distribution facilities?

A. Yes, FERC has specified a seven-part test to determine if a facility performs a distribution function. <u>See</u> FERC Order 888 at 31,770-31,771.

Q. Please explain FERC's seven-part test.

A. FERC's seven-part test is:

1. Local distribution facilities are normally in close proximity to retail customers.
2. Local distribution facilities are primarily radial in character.
3. Power flows into local distribution systems; it rarely, if ever, flows out.
4. When power enters a local distribution system, it is not reconsigned or transported on to some other market.

5. Power entering a local distribution system is consumed in a comparatively restricted geographical area.

6. Meters are based at the transmission/local distribution interface to measure power flows into the local distribution system.

7. Local distribution systems will be of reduced voltage.

As a result of the evolution of Cambridge's transmission and distribution system over the past decade, its 13.8 kV facilities now meet the standard to be classified as distribution facilities.

Q. Please provide the result of each test and explain how this may have differed from the determination made in D.P.U./D.T.E. 97-93, the last time this test was applied.

A. The table below compares the application of the FERC seven-part test with regard to the 13.8 kV facilities as serving a distribution function, in 1997 and after the merger, in 2007. An explanation of the results follows:

Test of 13.8 kV Facilities	1997	2007
1. Distribution in close proximity to retail customers	No	Yes
2. Distribution radial in character	No	Yes
3. Power flows in, rarely out	No	Yes
4. Power is used not just transported to other market	No	Yes
5. Power is consumed in the area	No	Yes
6. Meters are based at the interface	Yes	Yes
7. Low voltage levels	Yes	Yes

The FERC seven-part test was designed to determine what facilities operate as distribution facilities. In the case of Cambridge, in 1997 in D.P.U./D.T.E. 97-93 when the test was applied, the operating characteristics of 13.8 kV system did not meet the criteria for categorizing the 13.8 kV facilities as distribution (except for its low-voltage designation and the location of its meters). In fact, the 13.8 kV system was designed to be an integrated transmission system that provided a reliable interchange of power from multiple supply points (internal generation and interconnections with the New England bulk transmission system) to distribution substations. However, Cambridge's transmission and distribution system configuration has changed over the course of time, which has had an effect on the operating characteristics of the 13.8 kV facilities.

Currently, the 13.8 kV system no longer provides the numerous power paths that interconnect the generation facilities with Cambridge's internal bulk stations and other utilities bulk substations to supply the local distribution customers. With the addition of the new East Cambridge Bulk Substation, the network interconnecting capability of the 13.8 kV facilities has been displaced. Internal generation is now interconnected to circuits at the 115 kV level and provides the power flow to the bulk substations and to the New England grid. The 13.8 kV system on the other hand has become localized and provides radial links from the substations to customers' load. When power flows into the 13.8 kV system, it is used to serve the end-use customers in the area and is not transported into another market. As such, these factors support the fact that the 13.8 kV facilities now meet the criteria of FERC's seven-part test for reclassification as distribution facilities.

Q. What is your proposal with respect to the ratemaking treatment for the 13.8 kV facilities?

A. As mentioned above, the terms of the Settlement Agreement specify that the collection of costs from customers is to be transferred from transmission rates to distribution rates. NSTAR Electric proposes that this be accomplished through a revenue-neutral transfer of the revenue requirement that would have been collected in transmission rates to the distribution rates for Cambridge. This will ensure that neither NSTAR Electric nor customers receives or pays more than they otherwise would have.

Q. How will the revenue requirement of the Cambridge 13.8 kV system be calculated?

A. The revenue requirement is developed on Exhibit NSTAR-CLV-6, beginning at page 20, which is entitled "13.8 kV Transmission Rider to Attachment D" and is intended to represent the 13.8 kV component of Cambridge's overall transmission rate. Attachment D is intended for submission to FERC and to be applicable to Cambridge transmission billings for 2006.[2] Exhibit NSTAR-CLV-7 is an

[2] The current draft FERC tariff, Exhibit NSTAR-CLV-6, has a separate 13.8 kV calculation. However, if the final tariff does not incorporate a separate 13.8 kV calculation, then the 13.8 kV amount to be transferred will be calculated per the combined tariff both with and without the 13.8 kV facilities. The difference will be the amount that needs to be transferred to distribution rates.

illustrative sample calculation of the revenue requirement associated with Cambridge's 13.8 kV facilities that are to be transferred from transmission to distribution service using the FERC tariff rate formula, and based upon 2005 data. The amount that will be actually transferred from transmission to distribution will be based upon forecasted cost data for calendar year 2006, to be effective beginning January 2007. NSTAR Electric will transfer that portion of the Cambridge transmission revenues attributed to the 13.8 kV facilities to its distribution rates. In addition, after the close of 2006, NSTAR Electric will determine the final costs and revenue requirement for the 13.8 kV facilities, and an adjustment for the true-up amount will be made for customers in the Cambridge service territory in 2008. This reconciliation will be made in Cambridge's distribution and transmission rates. To ensure that this one-time adjustment affects only Cambridge's customers, the adjustment will be included directly in the distribution and transmission charges included in Cambridge's retail rate schedules. The reconciliation will ensure that there is neither an overcollection nor an undercollection.

Q. Please summarize Exhibit NSTAR-CLV-7.

A. The 13.8 kV transmission facilities' revenue requirement includes costs specifically relating to transmission of power through the 13.8 kV facilities within the City of Cambridge, and allocated general expenses that support the 13.8 kV transmission function. To the extent possible, the embedded cost values in the revenue requirement are derived from Cambridge's FERC Form No. 1. Any additional data not available in the FERC Form No. 1 are detailed in supporting workpapers. The supporting workpapers show the 13.8 kV transmission facilities analysis where the 13.8 kV allocation factors are developed for FERC Plant Accounts 360–374.

Q. What are the components of Cambridge's 13.8 kV transmission facilities' revenue requirement?

A. The primary cost of service was developed by first identifying costs directly associated with the transmission function. These costs include expenses directly related to the 13.8 kV transmission facilities plant investment and operations and maintenance ("O&M") expenses. The revenue requirement includes costs relating to the transmission function as well as allocated general costs that support the transmission function.

The revenue requirement also reflects rate base that includes 13.8 kV plant, plus allocated intangible and general plant. Deducted from this amount are allocations of accumulated depreciation and deferred income taxes. Added to this amount are 13.8 kV-related materials and supplies, prepayments, allowance for cash working capital and other regulatory assets/liabilities.

In accordance with the FERC formula rate, the 13.8 kV transmission facilities' investment base is multiplied by an overall rate of return and associated income tax percentage. This amount is then added to allocated depreciation and amortization expense, related municipal tax expense, related payroll tax expense, allocable O&M expenses, related administrative and general expenses and related support expenses.

Q. Has the Cambridge 13.8 kV transmission facilities' revenue requirement been credited for any tax credits or operating revenues received by Cambridge?

A. Yes. Related amortization of investment tax credit, related support revenues, related rents received from electric property and short-term and non-firm Point-to-Point service revenues have been credited to the cost of service, thus reducing total revenue requirement.

Q. How will the 13.8 kV revenue requirement transfer be accomplished?

A. The proposed method of transfer will be revenue neutral for NSTAR Electric and for each of Cambridge's rate classes. This would be accomplished by first reducing current transmission prices for each retail rate class by the percentage decrease in total transmission revenue requirement resulting from the transfer. Next, distribution prices for each rate class will be increased by the corresponding decrease in transmission prices for each rate class. Exhibit NSTAR-CLV-8 sets forth the transmission and distribution rate impacts to Cambridge's rate classes. Overall, there would be no difference to rates for Cambridge customers when transmission and distribution are added together.

Q. Will the new retail transmission rates for 2007 be consistent for all of NSTAR Electric customers?

A. Once the regulatory approvals are in place for the merger of the transmission tariffs and the transfer of the 13.8 kV facilities to distribution by January 2, 2007, the retail transmission rates for 2007 will be consistent for all of NSTAR Electric's customers.

VI. CONSOLIDATING DEPRECIATION RATES

Q. Does NSTAR Electric propose to implement the terms of the Settlement Agreement relating to establishing uniform depreciation rates?

A. Yes. Paragraph 2.6.2 permits the merged NSTAR Electric to consolidate depreciation rates for Boston Edison, Cambridge and Commonwealth "that are expense neutral at the functional group level." That is, the total depreciation expense for Boston Edison, Cambridge, and Commonwealth using the rates currently in effect will result in the same total depreciation expense under the new combined rates within each functional category (Intangible, Distribution and General).

Q. Have you prepared exhibits to illustrate the effect of producing new depreciation rates that are expense neutral at the functional levels for NSTAR Electric?

A. Yes, Exhibit NSTAR-CLV-9 sets forth the development of the depreciation accruals for all three electric companies at the functional levels using the old depreciation rates as applied to the test-year-end plant balances filed in D.T.E. 05-85. The combined companies' depreciation accruals at each of the functional levels are the dollar level basis on which new depreciation rates are formulated. Exhibit NSTAR-CLV-10, pages 1 and 2 set forth the development of the new depreciation rates for NSTAR Electric at the account and functional levels according to the methodology described further below. Page 1 of Exhibit NSTAR-CLV-10 shows the summary results. Page 2 of Exhibit NSTAR-CLV-10 provides a special analysis in developing the new depreciation rates for the General Plant — Leasehold Improvements. The special analysis is undertaken to show the results of amortizing these facilities over the remaining life of their respective leases. Exhibit NSTAR-CLV-11 sets forth the Depreciation Study that calculated annual depreciation accruals relating to the consolidated NSTAR Electric Plant filed by John J. Spanos, NSTAR Electric's depreciation expert, as Exhibit NSTAR-JJS-3 (of Exhibit NSTAR-1) in D.T.E. 05-85. The depreciation accrual rates for each distribution plant account from this study were used as the starting basis for determining the consolidated NSTAR Electric distribution plant account accruals as of June 30, 2005.

Q. Please describe the procedures used to develop the new rates as shown in the three exhibits to achieve expense neutrality at the functional level.

A. The procedures are set forth below for three functional levels of depreciation. The functional levels are Intangible Plant, Distribution Plant and General Plant. The Transmission Plant functional level is excluded, since approval of any changes is subject to the jurisdiction of FERC.

Q. How were new depreciation rates for Intangible Plant formulated?

A. Currently, all intangible plant (computer software) for all companies is amortized at a rate of 20 percent (five-year amortization). No change in the depreciation rates for the combined companies was required to remain expense neutral.

Q. What procedure was used to develop combined depreciation rates for Distribution Plant?

A. Distribution Plant is by far the largest element of depreciation expense contained in retail distribution rates. The first step in developing an expense-neutral, unified depreciation rate for Distribution Plant was to determine the annual depreciation accrual using the old rates. The balance by each FERC Plant Account (Accounts 360–373) as of June 30, 2005 was multiplied by the current depreciation rates in effect for each company. The total of these calculations for all companies was used to determine the annual accrual to be used after the application of the new depreciation rates. <u>See</u> Exhibit NSTAR-CLV-9, which illustrates the results.

The combined accrual rates for distribution plant were based on the depreciation study performed by NSTAR Electric in D.T.E. 05-85 and included as Exhibit NSTAR-CLV-11. All of the individual accrual rates for Distribution Plant from the above were reduced by 4.9838 percent so that the total depreciation expense under the combined rates approximately equals the depreciation expense using the old rates for this functional group. <u>See</u> Exhibit NSTAR-CLV-10, which shows these results. <u>Compare</u> the combined annual accrual for Distribution Plant of

$89,648,541 on Exhibit NSTAR-CLV-10 with the sum of the three companies, $89,648,551, set forth in Exhibit NSTAR-CLV-9.

Q. What procedure was used to develop new depreciation rates for General Plant?

A. Again, the first step in the process was to determine the annual depreciation accrual using the old rates. The balance by each FERC Plant Account (Accounts 390–398) as of June 30, 2005 was multiplied by the current depreciation rates in effect for each company. The total of these calculations for all companies was used to determine the annual accrual to be used after the application of the new depreciation rates. See Exhibit NSTAR-CLV-9, which shows the results. The new rates were developed in two phases. The first phase involved developing rates for the individual sub-account of Account – 390 Leasehold Improvements, so that the rates match the lives in the terms of the lease. The second phase is similar to what was done to depreciation plant. The depreciation rate for all the remaining accounts equal the proposed depreciation rate in the study multiplied by a factor (49.7437 percent) to make the total revenue neutral. See Exhibit NSTAR-CLV-10, which shows these results. Compare the combined annual accrual for General Plant of $6,442,325 on Exhibit NSTAR-CLV-10 with the sum of the three companies, $6,442,325, set forth in Exhibit NSTAR-CLV-9.

Q. Please explain the calculations involved in determining the rates for Leasehold Improvements.

A. Leasehold improvements are a part of Account 390 General Structures. Boston Edison currently has five major leased facilities that are currently being depreciated at a rate of 2.76 percent. The proposal is to amortize these facilities over the remaining life of their individual leases, thereby more appropriately matching expense with the expected life and use of these facilities. This is illustrated in Exhibit NSTAR-CLV-10, page 2.

Q. Do the Companies propose a new method of recording depreciation for General Plant?

A. Yes, the Companies seek approval to change the accounting treatment for their investment in general plant equipment from depreciation to amortizable property. The proposal is to adopt the terms of FERC Accounting Release No. 15 (AR-15). FERC adopted this accounting procedure in 1997 for high volume – low dollar value accounts. Under this approach, additions are grouped by vintage and amortized over a pre-determined period of time. The specific accounts that the Companies propose to include are:

- Account 391 — Office Equipment
- Account 393 — Stores Equipment
- Account 394 — Tools & Work Equipment
- Account 395 — Laboratory Equipment
- Account 397 — Communications
- Account 398 — Miscellaneous Equipment

This method was recommended in the recent depreciation study (see, e.g., Exhibit NSTAR-JJS-1, pages 21-22, filed in D.T.E. 05-85).

Q. Why is the Company seeking this change?

A. The assets in these accounts comprise a very high number of property retirement units, but constitute a very small percentage (1.5 percent) of total plant investment. The items in these accounts are relatively inexpensive and because of their size and mobility are very difficult to follow. For example, these accounts would include desks, chairs, radios, cafeteria equipment, and other similar items. If items break or are not useful, the fact is often not reported, which makes retirement accounting difficult. Amortization would reduce the records added, retired and maintained in the General Ledger and Property Records Systems, thereby reducing the time consumed for document preparation, data entry, computer processing, property unit listings and inventorying of equipment. The reduction of the effort on these plant accounts would permit resources to be devoted to the plant accounts with the larger investment.

Q. Has the Department previously approved this method of accounting?

A. This methodology is consistent with the approach applied by NSTAR Gas as approved by the Department in D.P.U. 91-60:

> The Department also accepts for purposes of this proceeding the Company's accounting change, for general plant equipment in accounts 391 through 398 and distribution plant equipment in account 387 as amortizable, rather than depreciable, property.

D.P.U. 91-60, at 3.

Q. Under the proposed arrangement, how would retirements be handled?

A. Individual retirements would not be recorded. If retirements must be recorded, all the advantages of changing to amortization described above are lost and the Companies would continue to depreciate these assets. Of course, when assets for a particular vintage year have been fully amortized both the asset and the reserve would be removed from the books.

Q. How does this change affect the depreciation rates?

A. For currently existing assets in these accounts, the depreciation rates will be the rates set forth in the depreciation study filed as Exhibit NSTAR-JJJ-3 in D.T.E. 05-85 (Exhibit NSTAR-CLV-11), multiplied by a factor of 49.7437 percent, as described above.

Q. What amortization period would be used to record new additions to these accounts?

A. The amortization period used will be those recommended in the depreciation study (Exhibit NSTAR-JJS-3, page 39). The amortization periods recommended for the general plant accounts in question are all 15 years, with the exception of computer equipment which is five years.

- Account 391 — Office Equipment
  - Office Furniture 15 years
  - Computers 5 years
- Account 393 — Stores Equipment 15 years
- Account 394 — Tools & Work Equipment 15 years
- Account 395 — Laboratory Equipment 15 years
- Account 397 — Communications 15 years
- Account 398 — Miscellaneous Equipment 15 years

VII. IMPACT ON SERVICE QUALITY INDICES

Q. What is the impact of the merger on the calculation of service quality benchmarks and reports filed with the Department?

A. Although Boston Edison, Cambridge and Commonwealth have already merged operations, they continue to report service quality performance on a company-by-company basis as required by the Department. See Department Order on NSTAR Compliance Filing in D.T.E. 99-84 (December 5, 2001). After the formal merger of the companies and the conclusion of the Department's review of service quality standards in D.T.E. 04-116, NSTAR Electric will propose whether and how service quality performance should be consolidated for the merged entity.

Q. Does this conclude your testimony?

A. Yes.

AGREEMENT AND PLAN OF MERGER

AGREEMENT AND PLAN OF MERGER ("Agreement") dated as of April 10, 2006, by and among Boston Edison Company, a Massachusetts utility corporation ("Boston Edison"), Commonwealth Electric Company, a Massachusetts utility corporation ("CEC"), Cambridge Electric Light Company, a Massachusetts utility corporation ("Cambridge"), and Canal Electric Company, a Massachusetts utility corporation ("Canal").

WITNESSETH:

WHEREAS, Boston Edison has an authorized capitalization consisting of (i) 100,000,000 shares of common stock, par value $1.00 per share ("Boston Edison Common Stock"), of which 75 shares are issued and outstanding; (ii) 2,660,000 shares of cumulative preferred stock, par value $100.00 per share ("Boston Edison Preferred Stock"), 430,000 shares of which (consisting of shares of two separate series) are issued and outstanding; and (iii) 8,000,000 shares of preference stock, par value $1.00 per share ("Boston Edison Preference Stock"), of which no shares are issued and outstanding;

WHEREAS, CEC has an authorized capitalization consisting of) 2,043,972 shares of common stock, par value $1.00 per share ("CEC Common Stock"), all of which shares are issued and outstanding;

WHEREAS, Cambridge has an authorized capitalization consisting of 346,600 shares of common stock, par value $1.00 per share ("Cambridge Common Stock"), all of which shares are issued and outstanding;

WHEREAS, Canal has an authorized capitalization consisting of 1,523,000 shares of common stock, par value $1.00 per share ("Canal Common Stock"), all of which shares are issued and outstanding; and

WHEREAS, the Boards of Directors of the respective parties hereto deem it advisable and in the best interests of CEC, Cambridge and Canal, and their respective stockholders to merge CEC, Cambridge and Canal with and into Boston Edison (the "Merger") in accordance with Section 96 of Chapter 164 of the Massachusetts General Laws and pursuant to this Agreement and the Articles of Merger attached hereto as Annex I and incorporated herein (the "Articles"), whereby the holders of shares of CEC Common Stock, Cambridge Common Stock and Canal Common Stock will exchange their shares for Boston Edison Common Stock;

NOW, THEREFORE, in consideration of the premises and the representations, warranties and agreements herein contained, the parties hereto agree that CEC, Cambridge and Canal shall be merged with into Boston Edison, which shall be the corporation surviving the Merger, and that the terms and conditions of the Merger, the mode of carrying it into effect, and the manner of converting and exchanging shares shall be as follows:

ARTICLE I
THE MERGER

(a) Subject to and in accordance with the provisions of this Agreement, the Articles shall be executed and acknowledged by each of Boston Edison, CEC, Cambridge and Canal, and thereafter delivered to the Secretary of State of The Commonwealth of Massachusetts for filing, as provided in Section 102A of Chapter 164 of the Massachusetts General Laws. The Merger shall become effective at such time as the Articles are filed as required by law with the Secretary of State of The Commonwealth of Massachusetts or such date, not more than thirty days after such filing, as may be specified in the Articles (the "Effective Time"). At the Effective Time, the separate existence of each of CEC, Cambridge and Canal shall cease and CEC, Cambridge and Canal shall be merged with and into Boston Edison (CEC, Cambridge, Canal and Boston Edison being sometimes referred to collectively herein as the "Constituent Corporations" and Boston Edison, the corporation designated in the Articles as the surviving corporation being sometimes referred to herein as the "Surviving Corporation");

(b) Prior to and after the Effective Time, Boston Edison, CEC, Cambridge and Canal, respectively, shall take all such actions as may be necessary or appropriate in order to effectuate the Merger. In this connection, Boston Edison shall issue the Boston Edison Common Stock which the holders of CEC Common Stock, Cambridge Common Stock and Canal Common Stock are entitled to receive as provided in Article II hereof. In the event that at any time after the Effective Time any further action is necessary or desirable to carry out the purposes of this Agreement and to vest the Surviving Corporation with full title to all properties, assets, rights, approvals, immunities and franchises of any of the Constituent Corporations, the officers and directors of each of the Constituent Corporations as of the Effective Time shall take all such further action.

ARTICLE II
TERMS OF CONVERSION AND EXCHANGE OF SHARES

At the Effective Time:

(a) Each share of Boston Edison Common Stock issued and outstanding immediately prior to the Merger shall not be converted or otherwise affected by the Merger, and each such share shall continue to be issued and outstanding and to be one fully paid and nonassessable share of the common stock of the Surviving Corporation;

(b) The shares of Boston Edison Preferred Stock issued and outstanding immediately prior to the Merger shall not be converted or otherwise affected by the Merger, and each such share shall continue to be issued and outstanding and to be one fully paid and nonassessable share of the particular series of preferred stock of the Surviving Corporation; and

(c) Each share of CEC Common Stock, Cambridge Common Stock and Canal Common Stock issued and outstanding immediately prior to the Merger shall, by virtue of the Merger and without any action on the part of any holder thereof, be converted into the following number of share of common stock of the Surviving Corporation, which thereupon shall be issued, fully paid and nonassessable: 0.0000088 in the case of CEC; 0.0000115 in the case of Cambridge; and 0.0000084 in the case of Canal.

ARTICLE III
ARTICLES OF ORGANIZATION AND BYLAWS

From and after the Effective Time, and until thereafter amended as provided by law, the Restated Articles of Organization of Boston Edison as in effect immediately prior to the Merger shall be and continue to be the Restated Articles of Organization of the Surviving Corporation. The purposes of the Surviving Corporation, the total number of shares and par value of each class of stock which the Surviving Corporation is authorized to issue and a description of each class of stock authorized at the Effective Time, with the preferences, voting powers, qualifications, special or relative rights or privileges as to each class and any series thereof then established, are as stated in such Restated Articles of Organization, which are attached hereto as Annex II and incorporated herein. From and after the Effective Time, the Bylaws of Boston Edison shall be and continue to be the Bylaws of the Surviving Corporation until amended in accordance with law.

ARTICLE IV
DIRECTORS AND OFFICERS

The persons who are directors and officers of Boston Edison immediately prior to the Merger shall continue as directors and officers, respectively, of the Surviving Corporation and shall continue to hold office as provided in the Bylaws of the Surviving Corporation. If, at or following the Effective Time, a vacancy shall exist in the Board of Directors or in the position of any officer of the Surviving Corporation, such vacancy may be filled in the manner provided in the Bylaws of the Surviving Corporation.

ARTICLE V
STOCK CERTIFICATES

As soon as practicable after the Effective Time the holders of outstand shares of CEC Common Stock, Cambridge Common Stock and Canal Common Stock shall deliver to the Surviving Company such shares in exchange for the appropriate number of shares of common stock of the Surviving Company as provided in Article II. At the Effective Time, each outstanding certificate which, prior to the Effective Time, represented CEC Common Stock, Cambridge Common Stock and Canal Common Stock shall be no longer be outstanding and shall be automatically cancelled and each holder thereof will cease to have rights with respect thereto, except to receive the appropriate number of shares of common stock of the Surviving Company in accordance with Article II..

ARTICLE VI
CONDITIONS OF THE MERGER

Consummation of the Merger is subject to the satisfaction of the following conditions:

(a) The Merger shall have received the approval of the holders of each class of common stock outstanding and entitled to vote thereupon of each of the Constituent Corporations as required by Section 96 of Chapter 164 of the Massachusetts General Laws.

(b) The issuance of Boston Edison Common Stock and the Merger shall have been approved by the Massachusetts Department of Telecommunications and Energy as required by Chapter 164 of the Massachusetts General Laws, by the Federal Energy Regulatory Commission ("FERC") as required by Section 203 of the FERC's regulations and by all other governmental agencies whose approval is necessary, appropriate or desirable.

ARTICLE VII
AMENDMENT AND TERMINATION

The parties hereto by mutual consent of their respective Boards of Directors may amend, modify, supplement or terminate (and the Merger and other transactions herein provided for abandoned) this Agreement in such manner as may be agreed upon by them in writing, at any time before or after approval of this Agreement by the stockholders of the Constituent Corporations.

ARTICLE VIII
EFFECTIVE TIME OF THE MERGER

Subject to the prior satisfaction of the conditions of the Merger set forth in Article VI hereof and the authority to terminate this Agreement as set forth in Article VII hereof, the Constituent Corporations shall do all such acts and things as shall be necessary or desirable in order to make the Effective Time occur as soon thereafter as practicable.

ARTICLE IX
MISCELLANEOUS

This Agreement may be executed in counterparts, each of which when so executed shall be deemed to be an original, and such counterparts shall together constitute but one and the same instrument.

N WITNESS WHEREOF, Boston Edison, CEC, Cambridge and Canal, pursuant to approval and authorization duly given by resolutions adopted by their respective Boards of Directors, have each caused this

IN WITNESS WHEREOF, Boston Edison, Commonwealth Electric Company, Cambridge Electric Company and Canal Electric Company, pursuant to approval and authorization duly given by resolutions adopted by their respective Boards of Directors, have each caused these Articles of Merger to be executed by its president or one of its vice presidents and its secretary or one of its assistant secretaries.

Dated: April 10, 2006

BOSTON EDISON COMPANY

By: Douglas S. Horan
Name: Douglas S. Horan
Title: Senior Vice President/Strategy, Law & Policy and General Counsel

By: James J. Judge
Name: James J. Judge
Title: Senior Vice President, Treasurer & Chief Financial Officer

COMMONWEALTH ELECTRIC COMPANY

By: Douglas S. Horan
Name: Douglas S. Horan
Title: Senior Vice President/Strategy, Law & Policy and General Counsel

By: James J. Judge
Name: James J. Judge
Title: Senior Vice President, Treasurer & Chief Financial Officer

CAMBRIDGE ELECTRIC LIGHT COMPANY

By: Douglas S. Horan
Name: Douglas S. Horan
Title: Senior Vice President/Strategy, Law & Policy and General Counsel

By: James J. Judge
Name: James J. Judge
Title: Senior Vice President, Treasurer & Chief Financial Officer

CANAL ELECTRIC COMPANY

By: ______________________
Name: Douglas S. Horan
Title: Senior Vice President/Strategy, Law & Policy and General Counsel

By: ______________________
Name: James J. Judge
Title: Senior Vice President, Treasurer & Chief Financial Officer

ANNEX I
to
Agreement and Plan of Merger

ARTICLES OF MERGER
of

<u>BOSTON EDISON COMPANY</u>
(A Massachusetts Utility Corporation)

and

<u>COMMONWEALTH ELECTRIC COMPANY</u>
(A Massachusetts Utility Corporation)
and

<u>CAMBRIDGE ELECTRIC LIGHT COMPANY</u>
(A Massachusetts Utility Corporation)

and

<u>CANAL ELECTRIC COMPANY</u>
(A Massachusetts Utility Corporation)

Pursuant to the provisions of Section 102A of Chapter 164 of the Massachusetts General Laws, the undersigned corporations adopt the following Articles of Merger for the purpose of merging Commonwealth Electric Company, Cambridge Electric Light Company and Canal Electric Company with and into Boston Edison Company, which shall be the Surviving Corporation:

1. Attached hereto and incorporated herein by reference is the Agreement and Plan of Merger dated as of April , 2006, of the undersigned corporations. The Surviving Corporation will furnish a copy of said agreement to any of its stockholders, or to any person who was a stockholder of a Constituent Corporation, upon written request and without charge. The Effective Time as defined therein is 12:01 A.M., Boston time on January 27, 2007.

2. The undersigned president or vice president and secretary or assistant secretary of each undersigned corporation hereby state under the penalties of perjury that the attached Agreement and Plan of Merger has been duly executed on behalf of such corporation and has been approved by the stockholders of such corporation and by the Department of Telecommunications and Energy of The Commonwealth of Massachusetts in the manner required by Section 96 of Chapter 164 of the Massachusetts General Laws.

3. The post office address of the initial principal office of the Surviving Corporation is 800 Boylston St.,, MA 02199.

4. The name, residence and post office address of each of the initial directors and the chairman, president, treasurer and secretary of the Surviving Corporation are as follows:

Name	Title	Residence	Post Office Address
Thomas J. May	Chairman of the Board, President and Chief Executive Officer	22 Longmeadow Drive Westwood, MA 02090	c/o 800 Boylston Street Boston, MA 02199
James J. Judge	Director, Senior Vice President, Treasurer and Chief Financial Officer	30 Cushing Hill Road Hanover, MA 02339	c/o 800 Boylston Street Boston, MA 02199
Douglas S. Horan	Director, Senior Vice President/Strategy, Law & Policy and General Counsel	171 Asbury St. Hamilton, MA. 01982	c/o 800 Boylston Street Boston, MA 02199
Richard J. Morrison	Secretary	60 Washburn Ave. Wellesley, MA. 02481	c/o 800 Boylston St. Boston, MA. 02199

5. The fiscal year of the Surviving Corporation initially adopted shall end on the last day of the month of December in each year.

6. The date and time initially fixed in the Bylaws for the annual meeting of the stockholders of the Surviving Corporation is 11:00 a.m. on the last Tuesday in April of each year.

[Remainder of this page intentionally left blank.]

Agreement and Plan of Merger to be executed as of the date first written above by its President or one of its Vice Presidents and Treasurer or Assistant Treasurer and its corporate or common seal to be affixed hereto and attested by its Secretary.

ATTEST:

Richard J. Morrison

Richard J. Morrison
Secretary

[BOSTON EDISON COMPANY SEAL]

BOSTON EDISON COMPANY

By: Douglas S. Horan
Name: Douglas S. Horan
Title: Senior Vice President/Strategy, Law & Policy and General Counsel

By: James J. Judge
Name: James J. Judge
Title: Senior Vice President, Treasurer & Chief Financial Officer

ATTEST:

Richard J. Morrison

Richard J. Morrison
Secretary

[COMMONWEALTH ELECTRIC COMPANY SEAL]

COMMONWEALTH ELECTRIC COMPANY

By: Douglas S. Horan
Name: Douglas S. Horan
Title: Senior Vice President/Strategy, Law & Policy and General Counsel

By: James J. Judge
Name: James J. Judge
Title: Senior Vice President, Treasurer & Chief Financial Officer

ATTEST:

Richard J. Morrison

Richard J. Morrison
Secretary

[CAMBRIDGE ELECTRIC LIGHT COMPANY SEAL]

CAMBRIDGE ELECTRIC LIGHT COMPANY

By: Douglas S. Horan
Name: Douglas S. Horan
Title: Senior Vice President/Strategy, Law & Policy and General Counsel

By: James J. Judge
Name: James J. Judge
Title: Senior Vice President, Treasurer & Chief Financial Officer

ATTEST:

Richard J. Morrison

Richard J. Morrison
Secretary

[CANAL ELECTRIC COMPANY SEAL]

CANAL ELECTRIC COMPANY

By: Douglas S. Horan

Name: Douglas S. Horan
Title: Senior Vice President/Strategy, Law & Policy and General Counsel

By: James J. Judge

Name: James J. Judge
Title: Senior Vice President, Treasurer & Chief Financial Officer

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

BOSTON EDISON COMPANY CAMBRIDGE ELECTRIC LIGHT COMPANY COMMONWEALTH ELECTRIC COMPANY CANAL ELECTRIC COMPANY		DOCKET NO. EC06-___-000
BOSTON EDISON COMPANY		DOCKET NO. ES06-___-000

APPLICATION OF THE NSTAR OPERATING COMPANIES UNDER SECTION 203 OF THE FEDERAL POWER ACT TO MERGE AND CONSOLIDATE THEIR FACILITIES AND OF BOSTON EDISON COMPANY TO INCREASE ITS AUTHORIZATION TO ISSUE SHORT-TERM DEBT

Boston Edison Company ("BECo"), Cambridge Electric Light Company ("Cambridge"), Commonwealth Electric Company ("Commonwealth"), and Canal Electric Company ("Canal") (collectively, "the NSTAR Operating Companies" or "Applicants") hereby submit this Joint Application under Section 203 of the Federal Power Act ("FPA") and Part 33 of the Commission's regulations for authorization and approval for BECo to acquire the respectively owned jurisdictional facilities of its affiliates, Cambridge, Commonwealth and Canal ("the Transaction"). The Transaction will not create anticompetitive effects, impair the effectiveness of regulation, increase customer costs, or result in cross-subsidies or asset encumbrances. The Transaction easily satisfies the standard of consistency with the public interest as set forth in Section

203 of the FPA and the Commission's *Merger Policy Statement*;[1] and is in compliance with the information requirements established by Section 33 of the Commission's regulations as modified by Order No. 642[2] and as further modified by Order No. 669 and 669-A.[3] Accordingly, the Applicants seek approval of the Transaction within the sixty day period contemplated by Order No. 642 and Order No. 669 (collectively, "the Merger Orders") for mergers that do not present substantive issues or require a competitive analysis.[4]

In light of the Transaction, BECo also seeks under Section 204 of the FPA an increase in its authorization to issue short-term debt from $450 million, the current authorized level, to $655 million representing the aggregate short-term debt authorization requested on April 5, 2006 for BECo, Cambridge and Commonwealth in Docket Nos. ES06-33-000, ES06-32-000 and ES06-34-000, respectively. The authorization is requested for the period beginning with the consummation of the Transaction and ending December 31, 2008.[5]

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1 *Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement*, Order No. 592, III FERC Stats. & Regs. ¶ 31,044 (1996) (codified at 18 C.F.R. § 2.26) ("Merger Policy Statement").

2 *See* information submitted under 18 C.F.R. § 33.2(a) through (j), Part VIII, at pp. 14, *et seq.*; *See also Revised Filing Requirements Under Part 33 of the Commission's Regulations*, Order No. 642, FERC Stats. & Regs. ¶ 31,111 at 31,874, 31,876 (2000) ("Order No. 642"), *order on reh'g*, 94 FERC ¶ 61,289 (2001) ("Order No. 642-A").

3 *Transactions subject to FPA Section 203*, Docket No. RM05-34-000, 113 FERC ¶ 61,315 (2005) ("Order No. 669"); *order on reh'g*, Order No. 669-A, April 24, 2006.

4 *See* Order No. 642 at 31,876.

5 See page 22, *infra* for the request to increase BECo's short-term debt authority.

SECTION 203 APPLICATION

I. GOVERNING STATUTE AND JURISDICTIONAL STATEMENT

The Commission may approve the Transaction under Section 203 of the FPA, as amended by Section 1281 of the Energy Policy Act of 2005 ("EPACT 2005"),[6] which applies to merger applications filed on or after February 8, 2006. As revised, Section 203 establishes a jurisdictional minimum of $10 million and broadens the Commission's jurisdiction to include generation as well as transmission facilities. The Cambridge and Commonwealth jurisdictional transmission facilities BECo is acquiring each exceed in value the FPA jurisdictional minimum.[7]

II. BACKGROUND

Each Applicant is a subsidiary of NSTAR, a Massachusetts business trust which is a "single-state" public utility holding company as contemplated by the Public Utility Holding Company Act of 2005 ("PUHCA 2005").[8] Each Applicant is also a public utility as defined in Section 201(e) of the FPA, 16 U.S.C. § 824(e). Other than Canal, each Applicant is engaged in the provision of regulated transmission and distribution services and default electric service for retail customers in eastern Massachusetts.[9] As a result of the Transaction, BECo will acquire Cambridge, Commonwealth and Canal, and will change its name to NSTAR Electric Company ("NSTAR Electric").

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[6] Title XII of Pub. L. No. 109-58, 119 Stat. 594 (2005) is styled as the Energy Policy Act of 2005.

[7] Order No. 669 at PP 116-117.

[8] On March 10, 2006, NSTAR, on behalf of itself and BECo, requested waiver of the requirements of PUHCA 2005 in Docket No. PH06-26-000.

[9] Technically, the term for "default" service in Massachusetts is "basic" service.

During the several years prior to the Transaction, the Applicants restructured their electric operations by divesting their generating assets, replacing many of their former purchase power agreements with load following purchases from various suppliers,[10] and committing their transmission facilities to operation and control by ISO New England, Inc. ("ISO-NE"), a Commission approved Regional Transmission Organization or "RTO."[11] The intent underlying these initiatives was withdrawal from the generation business except to serve retail default customers to the extent required by the Massachusetts Department of Telecommunications and Energy ("MDTE"). In short, BECo, as survivor of the Applicants, will remain chiefly a wires company delivering electric power generated by others to wholesale and ultimate consumers residing in its distribution service area.

III. THE APPLICANTS AND THEIR PARENT

NSTAR: NSTAR, which was created in 1999 in connection with the merger of BEC Energy and Commonwealth Energy System,[12] owns all the common stock of each of the Applicants. Through the Applicants and NSTAR Gas Company ("NSTAR Gas"), NSTAR serves approximately 1.4 million customers in Massachusetts, including approximately 1.1 million electric distribution customers in 81 communities and

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[10] The Applicants and their affiliate "MATEP" on August 1, 2005 in Docket Nos. ER02-246-000 and ER98-1992-000, respectively, filed for renewal of their market-based rate ("MBR") authority, which the Commission accepted on November 3, 2005, 113 FERC ¶ 61,123 (2005). Except for MATEP which has only 87.8 MW of generating capacity, the Applicants would use the MBR authority solely for portfolio management purposes and will not otherwise engage in MBR transactions.

[11] *ISO New England, Inc., et al.*, 106 FERC ¶ 61,280 (2004).

[12] *See BEC Energy and Commonwealth Energy System* ("*BEC Energy*"), 88 FERC ¶ 61,002 (1999).

approximately 300,000 natural gas distribution customers in 51 communities. Those operations accounted for approximately 96% of NSTAR's consolidated operating revenues in each of the last four years. NSTAR also engages in non-utility, unregulated operations including local energy operations, telecommunications, and liquefied natural gas operations.

BECo: BECo provides service chiefly in metropolitan Boston, an area of about 590 square miles encompassing the City of Boston and 39 surrounding cities and towns. BECo's electric distribution system consists of approximately 22,003 circuit-miles and substations with a capacity of approximately 10,822 MVA. BECo also owns and operates approximately 524 circuit-miles of interconnected transmission lines of 115 kV to 345 kV, including 176 circuit-miles of 230-345 kV lines and 348 circuit-miles of 115 kV lines. BECo's transmission facilities include substations with a capacity of approximately 3,500 MVA. BECo expects to place in service within the next several weeks Phase I of its 345 kV Transmission Reliability Project. Phase I consists of two new underground 345 kV transmission lines and related facilities which will substantially increase its 345 kV transmission investment and substantially increase transmission import capability into the Greater Boston area. Some 663,000 retail customers and several other electric systems and independent generators are connected to the BECo system.[13]

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[13] BECo has three subsidiaries; BEC Fund LLC and BEC Fund II (jointly, the "BEC Financing Subs") and Harbor Electric Energy Company ("HEEC"). The BEC Financing Subs are bankruptcy remote special purpose entities that administer securitized transition property resulting from the advent of retail access in Massachusetts. HEEC delivers energy from BECo to the Massachusetts Water Resources Authority via an underwater 115 kV cable.

Cambridge: Cambridge's electric service territory encompasses about seven square miles consisting primarily of the City of Cambridge. Cambridge owns and operates approximately 7.3 circuit-miles of 115 kV interconnected transmission lines plus certain 13.8 kV facilities which have been deemed to serve a transmission function.[14] Transmission facilities include substations with a capacity of approximately 311,000 kilovolt-amperes. Cambridge's electric distribution system consists of approximately 584 circuit-miles and substations with a capacity of approximately 218 MVA. Some 45,900 retail customers and two wholesale systems are connected to the Cambridge system. In addition, Cambridge provides wheeling services for an independent generating company which is located within its system.

Commonwealth: Commonwealth's electric service territory includes about 1,100 square miles in 40 communities in southeastern Massachusetts, including Cape Cod, Martha's Vineyard, and all or part of Plymouth and Bristol Counties. Commonwealth owns and operates approximately 357.5 circuit-miles of interconnected transmission lines of 115 kV to 345 kV, including 297.6 circuit-miles of 115 kV and 59.9 circuit-miles of 345 kV lines. Transmission facilities include substations with a capacity of approximately 475,000 kilovolt-amperes. Commonwealth's electric distribution system consists of approximately 10,744 circuit-miles and substations with a capacity of

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[14] *See* pages 18-19, Part VIII(d) describing a proposed change in the jurisdictional status of the Cambridge 13.8 kV facilities.

approximately 1,814 MVA. Some 327,000 retail customers, four wholesale customers and several independent generators are connected to the Commonwealth system.[15]

Canal: In the past in order to provide service to its affiliates, Canal had ownership shares in generating companies, owned and operated generating facilities and engaged in the purchase and sale of electricity at wholesale. Canal never had retail customers. Canal has divested its direct and indirect generation ownerships, and does not currently own or operate any transmission or distribution facilities. However, Canal does have a 3.4 percent equity ownership share of New England Hydro-Transmission Electric Company and New England Hydro Transmission Corporation ("HQ Companies"). As a result of that ownership, Canal has been entitled to enter into a capital lease, pursuant to which it still owed as of year-end 2005 approximately $7.0 million in connection with the Hydro-Quebec transmission facilities owned by the HQ Companies. Canal has also entered into an agreement for the use of the HQ Companies' transmission lines for the benefit of Cambridge and Commonwealth.

IV. DESCRIPTION OF THE TRANSACTION

The Transaction will consist of a merger under Massachusetts law, whereby each of Cambridge, Commonwealth and Canal will merge with and into BECo. As a result of the merger, and by operation of the law, the facilities, properties and other rights, assets, franchises and liabilities will vest in BECo. The Cambridge and Commonwealth debt will be retired. Shares of Cambridge, Commonwealth and Canal

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[15] Commonwealth has one wholly owned subsidiary; CEC Fund LLC, also a bankruptcy remote special purpose entity that administers securitized transition property resulting from the advent of retail access in Massachusetts.

will be converted into shares of BECo, all of which will be held by NSTAR, and those three companies will cease to exist as separate companies. BECo will be the sole surviving corporate entity. However, as noted above, currently the plan is to change BECo's name to NSTAR Electric Company either upon the consummation of the Transaction or thereafter. Except for the name change and the acquisition of the Cambridge, Commonwealth and Canal assets through the merger, BECo, as renamed NSTAR Electric Company, will be the same company after the Transaction as it was before.

V. Transfer of Contracts

Cambridge, Commonwealth and Canal are parties to several FPA jurisdictional contracts in which they are the "providers" of service. As a result of the Transaction, BECo under Massachusetts law will succeed to those three companies' assets and liabilities, inclusive of their contracts and all their rights and obligations pursuant to those contracts, by operation of law without the need for formal "assignment and assumption" agreements.[16] These contracts are listed in Attachment 1 to this Application.[17] The Applicants' request for approval of the Transaction under Section

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[16] The majority of these contracts contain provisions stating that the Cambridge, Commonwealth or Canal rights and obligations may be unilaterally transferred to a third party in the event of the merger or consolidation with that third party or are silent in which case the contract is deemed assignable, absent certain conditions none of which is present here. *American Employers' Ins. Co. v. City of Medford*, 38 Mass. App. Ct. 18, 22 (1995), *review denied*, 419 Mass. 111 (1995).

[17] After the consummation, BECo (or NSTAR Electric Company, depending on the new name of the company) will make any appropriate notice of succession filings under section 205 of the FPA to implement the Transaction.

203 includes the transfer of these contracts from Cambridge, Commonwealth and Canal to BECo.[18]

VI. THE PUBLIC INTEREST

A. INTRODUCTION – MERGER APPROVAL STANDARD

Section 1289 of EPACT 2005 containing the revised Section 203 of the FPA preserves the preexisting FPA standard for approving mergers and related transactions, which is that they must be "consistent with the public interest." This standard was explained in *IES Industries, Inc., et al.*, 65 FERC ¶ 62,191 at 64,416 (1993) (footnote omitted):

> An applicant need not show that a positive benefit will result from a proposed merger or disposition of facilities in order to support a public interest finding. Rather, an applicant is required to make a full disclosure of all material facts and to show affirmatively that the disposition is consistent with the public interest.

This public interest finding thus requires a showing of consistency or compatibility with the public interest, not that the transaction furthers or is the only means of achieving the public interest. There is no requirement that applicants make a showing of a positive benefit of the merger.[19] In the *Merger Policy Statement*[20] and in Order No.

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[18] The Commission has held that a provider of services under jurisdictional contracts must obtain Commission approval under Section 203 to assign those contracts. *Cf., see New England Power Company, et al.*, 83 FERC ¶ 61,275 (1998).

[19] *Pacific Power & Light Co. v. FPC*, 111 F.2d 1014, 1016 (9th Cir. 1940); *Northeast Utilities Service Co. v. FERC*, 993 F.2d 937, 951 (1st Cir. 1993), quoted in *Entergy Services Inc. and Gulf States Utilities Co.*, 65 FERC ¶ 61,332 at 62,471 (1993). *Entergy Services, Inc. and Gulf States Utilities Co.*, 62 FERC ¶ 61,073 at 61,370 (1993) (footnotes and citations omitted); *Utah Power & Light Co., et al.*, 47 FERC ¶ 61,209 at 61,750 (1989), *remanded on other grounds, Environmental Action, Inc. v. FERC*, 939 F.2d 1057 (D.C. Cir. 1991).

[20] *Merger Policy Statement*, *supra* note 1.

642,[21] the Commission said that it would consider three elements in evaluating merger applications: the effects of the merger on competition, on regulation, and on rates. Due to the replacement of PUHCA 1935 by PUHCA 2005, Order No. 669 eliminates the "regulatory effect" criterion at least with respect to wholesale regulation. However, Section 203 of the FPA as revised by Section 1289 of EPACT 2005 and as implemented by Order No. 669, adds a prohibition against inter-affiliate cross-subsidization and asset encumbrances. Based on these criteria, the Transaction is clearly consistent with the public interest.

B. COMPETITION

The Transaction will have no adverse effect on competition.[22] Because the Transaction is wholly internal to the NSTAR corporate family, it will not affect the relative market shares of any market participant, and will have no effect on market concentration or competitive conditions, which will be exactly the same before and after the Transaction is consummated. The Commission has concluded that internal transfers or corporate restructurings have no adverse effect on competition.[23]

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[21] Order No. 642, *supra* note 2, at 31,872.

[22] *Merger Policy Statement* at 30,111-12; *see also* Section 2.26(b) of the Commission's regulations.

[23] *See* Order No. 642 at 31,902. *See also Progress Energy, Inc.*, 97 FERC ¶ 62,192 (2001); *PP&L Res., Inc.*, 90 FERC ¶ 61,203 at 61,649 (2000).

C. RATES

The Transaction will have no adverse effect on rates.[24] NSTAR has already achieved substantial operating savings and efficiencies through NSTAR Electric & Gas Corporation, a service company which provides common employees and other services for the Applicants. Nevertheless, even without personnel reductions which are not anticipated, the consolidation will produce some savings and efficiencies, which will more than offset the limited transaction costs likely to be incurred in achieving the consolidation of the Applicants' businesses. Also, the Applicants do not anticipate the incurrence of any material post-Transaction transition costs. Therefore, the Transaction will have no adverse impact on the Applicants' FPA jurisdictional transmission charges. Also, for the above stated reasons, the Applicants' retail rates for distribution services and for default services to retail customers will not be adversely impacted by the Transaction and, in any event, those rates are subject to the jurisdiction of the MDTE. In fact, a filing is being made today with the MDTE seeking the MDTE's approval of the Transaction. In summary, the nature of the Transaction is such that there are no circumstances in which any adverse rate impacts could be experienced due to the Transaction.

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[24] *Merger Policy Statement* at 30,123. The consolidation of the Applicants' transmission facilities could increase costs to some customers, but any such increases would be offset by decreases to other customers with the result that the net rate impact from the consolidation would be essentially zero. In any event, Section 203 applicants are required to protect ratepayers only from transaction and transition costs that exceed merger savings. *See, e.g., Old Dominion Electric Cooperative and New Dominion Electric Cooperative*, 110 FERC ¶ 61,274 at P 22 (2005) citing in n.10, *New York State Electric & Gas Corp.*, 86 FERC ¶ 61,020 at 61,053, *order denying reh'g*, 86 FERC ¶ 61,284 at 62,022-23 (1999) and *Jersey Central Power & Light Co.*, 87 FERC ¶ 61,014 at 61,039 (1999).

D. Regulation

Although the Commission no longer considers impact on wholesale regulation, it should be noted that the Transaction will have no effect on either wholesale or retail regulation. The electric operations of the Applicants will still be subject to the same regulation and oversight by this Commission and the MDTE after the consolidation as they were before. The only difference is that these operations will be conducted by one company rather than four. In fact, the consolidation of the four companies into a single company will facilitate regulatory review and reduce the cost of regulation to the MDTE, this Commission, and the Applicants' ratepayers. Moreover, the MDTE has approval power over the Transaction and must also approve any changes in retail rates resulting from the Transaction. In sum, the proposed Transaction will not impair either state or federal regulatory authority. To the contrary, the Transaction is likely to facilitate and improve the regulatory process with respect to the Applicants' operations.

E. Cross-Subsidization

Section 203(4) of the FPA requires the Commission to determine that a transaction "will not result in cross-subsidization of a non-utility associate company or the pledge or encumbrance of utility assets for the benefit of an associate company." Alternatively, Section 203(4) requires a showing that any cross-subsidy or asset pledge is consistent with the public interest. Order No. 669 and 669-A, which implement the Commission's revised Section 203 authority, require a new "Exhibit M" to explain either that a transaction would not result in a prohibited cross-subsidy or asset pledge or that any such cross-subsidy or asset pledge which might occur is consistent with the public interest. The "Exhibit M," as required by Order No. 669, is attached in verification form.[25]

BECo's acquisition of its affiliates' assets does not involve any cross-subsidization between regulated and non-regulated affiliates. BECo is acquiring only regulated transmission or distribution assets, or assets such as general plant related to transmission and distribution facilities, at book value and is not acquiring assets owned prior to the Transaction by any non-regulated company. Moreover, the assets being acquired and commingled with BECo's assets continue to serve the Commonwealth, Cambridge and BECo customers on a commingled basis. Thus, the Transaction does not effectuate any change in the "status quo ante" with respect to affiliate abuse and does not create any new opportunity to engage in affiliate abuse.

The Transaction also does not involve a pledge or encumbrance by BECo, the surviving company, of its assets for the benefit of any associated company. BECo is not pledging its assets to the three companies being merged into BECo, and those three companies will cease to exist following the consummation of the Transaction. In addition, BECo is not assuming the long-term debt of Cambridge and Commonwealth which is being cancelled. BECo will assume, as noted above, Canal's obligations under its capital lease with the HQ Companies. However, this assumption does not appear to constitute a pledge or encumbrance of utility assets as contemplated by Section 203(4),

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[25] Prior to EPACT 2005 and Order No. 669, the Commission had expressed similar affiliate abuse concerns in a case involving the sale of generating assets between affiliates. The Commission announced this new policy on July 29, 2004 in *Allegheny Energy Supply Company, LLC*, 108 FERC ¶ 61,082 (2004).

and, in any event, BECo is also acquiring Canal's rights pursuant to the lease and Canal's corresponding equity ownership share in the HQ Companies.

Order No. 669-A, which applies to the cross-subsidization, does not become effective until June 15, 2006. Therefore, the Exhibit M verification accompanying this Application complies with Order No. 669. However, the Applicants provides the following supplementary statement in accordance with Order No. 669-A which requires a detailed explanation

> "[o]f how applicants are providing assurance that the proposed transaction will not result in cross-subsidization of a non-utility associate company or pledge or encumbrance of utility assets for the benefit of an associate company..."

Order No. 669-A at P 144. There can be no such subsidy resulting from the Transaction since the parties to the Transaction include only regulated utilities and do not include any non-regulated utilities. The Order No. 669-A criteria are also satisfied even if the Commission's regulation has a broader sweep, as shown in the discussion below regarding the four criteria contained in the Commission's regulation:

Criterion 1: The Transaction does involve transfers of facilities between traditional utility associate companies. However, the transferor utilities are going out of business, and thus, are not the recipients of any indirect or direct subsidies. In addition, as noted above, the transfer of facilities is being recorded on BECo's books on a net book value basis so that there is no change in the net book value of the transferred facilities that could cause a subsidy to BECo or any adverse effect on BECo or its affiliates participating in the Transaction.

Criteria 2-4: This Transaction will not result in new issuances of securities by BECo for the benefit of any of its affiliates. BECo, as a result of the Transaction, has not made any new pledges or created any encumbrances of its assets. There are no new affiliate contracts between BECo and any affiliate whether regulated or non-regulated resulting from the Transaction.

Order No. 669-A also requires Applicants to disclose "existing pledges and/or encumbrances of utility assets." Except as discussed above with respect to the Canal lease and the about-to-be-cancelled Cambridge and Commonwealth long-term debt, the Applicants are unaware of any "existing pledge and/or encumbrances of utility assets" other than the Cambridge and Commonwealth bonds which are about to be refunded. Accordingly, the Applicants have established that the Transaction does not involve a prohibited cross-subsidization or asset pledge or encumbrance pursuant to both Order No. 669 and 669-A criteria.

VII. TRANSMISSION

Although the Applicants own transmission facilities, transmission service over the regional pool transmission facilities or "PTF" in New England is provided by ISO-NE through its Transmission, Markets and Services Tariff, FERC Electric Tariff No. 3 ("ISO-NE Tariff"). Transmission service over local transmission facilities or "non-PTF" is provided under individual transmission-owning utilities' "Schedule 21" local service schedules to the ISO-NE Tariff. As of consummation of the Transaction, the Applicants will report their respective PTF costs to ISO-NE, collectively, rather than individually as they do now. On or before sixty days prior to the consummation of the Transaction, BECo will submit to this Commission any Schedule 21 revisions that may be necessary or appropriate as a result of its acquisition of the Cambridge, Commonwealth and Canal facilities.[26]

VIII. INFORMATION SUBMITTED UNDER 18 CFR § 33.2(A) THROUGH (I)

(a) The exact name of the applicants and their principal business addresses:

Boston Edison Company
800 Boylston Street
Boston, MA 02199

Canal Electric Company
800 Boylston Street
Boston, MA 02199

Cambridge Electric Light Company
800 Boylston Street
Boston, MA 02199

Commonwealth Electric Company
800 Boylston Street
Boston, MA 02199

(b) The names and addresses of the persons authorized to receive notices and communications regarding the application, including phone and fax numbers, and E-mail addresses:

Neven Rabadjija, Esq.
Associate General Counsel
Mary E. Grover, Esq.
Assistant General Counsel
NSTAR Electric & Gas Corporation
800 Boylston Street, P1700
Boston, MA 02199-8003
Telephone: 617/424-2105
Facsimile: 617/424-2733
E-mail: neven_rabadjija@nstaronline.com
E-mail: mary_grover@nstaronline.com

Carmen L. Gentile, Esq.
Thomas L. Blackburn, Esq.
Robert T. Stroh, Esq.
Bruder, Gentile & Marcoux, L.L.P.
1701 Pennsylvania Ave, N.W.
Suite 900
Washington, D.C. 20006-5807
Telephone: 202/296-1500
Facsimile: 202/296-0627
E-mail: clgentile@brudergentile.com
E-mail: tlblackburn@brudergentile.com
E-mail: rtstroh@brudergentile.com

(c) A description of the applicants, including:

(1) All business activities of the applicant, including authorizations by charter or regulatory approval (to be identified as Exhibit A to the application):

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[26] *See* Part VIII, Section (d) describing a transfer subject to MDTE approval of certain Cambridge 13.8 kV facilities from FERC rate jurisdiction to MDTE rate jurisdiction.

The Applicants' public utility operations are referred to in Exhibit A and are described in Parts II and III, Pages 3-7. Each Applicant is a public utility under Part II of the FPA. Exhibit B identifies each of the Applicants' affiliates and describes their respective business activities.

(2) A list of all energy subsidiaries and energy affiliates, percentage ownership interest in such subsidiaries and affiliates, and a description of the primary business in which each energy subsidiary and affiliate is engaged (to be identified as Exhibit B to the application):

Exhibit B provides the referenced information for both energy and non-energy subsidiaries and affiliates. Energy-related affiliates are identified by asterisk.

(3) Organizational charts depicting the applicant's current and proposed post-transaction corporate structures (including any pending authorized but not implemented changes) indicating all parent companies, energy subsidiaries and energy affiliates unless the applicant demonstrates that the proposed transaction does not affect the corporate structure of any party to the transaction (to be identified as Exhibit C to the application):

The Transaction does not affect the NSTAR corporate structure except that BECo acquires Cambridge, Commonwealth and Canal and those three companies cease to exist. *See* Parts II, III and IV, Pages 3-8. Exhibits C-1 and C-2 show the pre- and post-Transaction organizational charts. The sole difference between the two exhibits is the disappearance of Cambridge, Commonwealth and Canal from the post-Transaction exhibit.

(4) A description of all joint ventures, strategic alliances, tolling arrangements or other business arrangements, including transfers of operational control of transmission facilities to Commission approved Regional Transmission Organizations, both current, and planned to occur within a year from the date of filing, to which the applicant or its parent companies, energy subsidiaries, and energy affiliates is a party, unless the applicant demonstrates that the proposed transaction does not affect any of its business interests (to be identified as Exhibit D to the application):

The Transaction does not affect the Applicants' business interests, which remain the same both before and after the Transaction except that BECo acquires Cambridge, Commonwealth and Canal which cease to exist. *See* Parts II, III, and IV, Pages 3-8. *See also* Exhibit D.

(5) The identity of common officers or directors of parties to the proposed transaction (to be identified as Exhibit E to the application):

Exhibit E shows the common officers and directors of NSTAR and each of the Applicants.

(6) A description and location of wholesale power sales customers and unbundled transmission services customers served by the applicant or its parent companies, subsidiaries, affiliates and associate companies (to be identified as Exhibit F to the application):

The Applicants have no wholesale power sales customers. A list of customers connected to their LNS systems and their interconnection agreements is shown in Exhibit F. All customers are located within ISO-NE.

(d) A description of jurisdictional facilities owned, operated, or controlled by the applicant or its parent companies, subsidiaries, affiliates, and associate companies (to be identified as Exhibit G to the application):

The Applicants' jurisdictional facilities are described in Exhibits G-1, G-2 and G-3 which show the Applicants' transmission ownership by miles, and by voltage and which contain backup transmission line and substation information. In addition to the facilities therein described, Cambridge owns and operates a 13.8 kV system which exists principally within the City of Cambridge the costs of which are presently charged to Cambridge's customers through Cambridge's Schedule 21 to the ISO-NE Tariff. This system has been used for the subtransmission purpose of delivering power throughout the City of Cambridge to retail and wholesale customers and under the "seven-part test" has been classified as a Commission jurisdictional system. However, certain changes have been made to the Cambridge system, including the addition of two 115 kV/14 kV transformers which have affected the system's operating characteristics. Accordingly, the present intent is to file with the MDTE asking to transfer the cost recovery for the Cambridge 13.8 kV system to MDTE jurisdictional rates. If this filing is made and if it is approved to be effective upon or prior to the consummation of the merger, the BECo Schedule 21 will not apply to these facilities and their associated costs.

(e) A narrative description of the proposed transaction for which Commission authorization is requested, including:

(1) The identity of all parties involved in the transaction;

(1) The parties to the transaction are BECo, Commonwealth, Cambridge and Canal. NSTAR is also a party to the Transaction since NSTAR owns all of the stock of Commonwealth, Cambridge and Canal and such stock will be converted into shares of BECo, all of which will be held by NSTAR. *See "Description of the Transaction,"* Part IV, Pages 7-8.

(2) All jurisdictional facilities and securities associated with or affected by the transaction (to be identified as Exhibit H to the application);

(3) The consideration for the transaction; and

(4) The effect of the transaction on such jurisdictional facilities and securities.

(2)-(4) The jurisdictional facilities associated with the Transaction are described in Exhibit G. There will be no change in the status of those facilities as a consequence of the Transaction. There is no consideration underlying the Transaction which is an internal corporate reorganization without a change in NSTAR's ultimate ownership. *See*

"*Description of the Transaction*," Part IV, Pages 7-8. As shown in Exhibit H, the long-term debt securities of Cambridge and Commonwealth will be redeemed as a consequence of the Transaction. All the Cambridge, Commonwealth and Canal common equity is owned by NSTAR and will be converted into shares of BECo upon consummation of the Transaction. In light of the Transaction, this application also includes a request under Section 204 of the FPA for BECo short-term debt authorization in the amount of $655 million reflecting the aggregate of the amounts requested for BECo, Cambridge and Commonwealth in Docket Nos. ES06-33-000, ES06-32-000 and ES06-34-000, respectively (*see* Section IX herein). Otherwise, the Transaction does not affect publicly held securities.

(f) All contracts related to the proposed transaction together with copies of all other written instruments entered into or proposed to be entered into by the parties to the transaction (to be identified as Exhibit I to the application):

The corporate resolution authorizing the Transaction and other Transaction related documents are contained in Exhibit I.

(g) A statement explaining the facts relied upon to demonstrate that the proposed transaction is consistent with the public interest. The applicant must include a general explanation of the effect of the transaction on competition, rates and regulation of the applicant by the Commission and state commissions with jurisdiction over any party to the transaction. The applicant should also file any other information it believes relevant to the Commission's consideration of the transaction. The applicant must supplement its application promptly to reflect in its analysis material changes that occur after the date a filing is made with the Commission, but before final Commission action. Such changes must be described and their effect on the analysis explained (to be identified as Exhibit J to the application):

The Applicants' statement showing the consistency of their Transaction with the public interest is shown under the heading "*The Public Interest*", Part VI, Pages 9-15.

Any material changes to the Transaction will be filed as Exhibit J if and when such changes are made prior to approval of the Transaction.

(h) If the proposed transaction involves physical property of any party, the applicant must provide a general or key map showing in different colors the properties of each party to the transaction (to be identified as Exhibit K to the application):

Maps showing the Applicants' physical public utility properties are contained in Exhibit K.

(i) If the applicant is required to obtain licenses, orders, or other approvals from other regulatory bodies in connection with the proposed transaction, the applicant must identify the regulatory bodies and indicate the status of other regulatory actions, and provide a copy of each order of those regulatory bodies that relates to the proposed transaction (to be identified as Exhibit L to the application). If the regulatory bodies issue orders pertaining to the proposed transaction after the date of filing with the Commission, and before the date of final Commission action, the applicant must supplement its Commission application promptly with a copy of these orders.

The Transaction has been approved by the board of directors of the Applicants. The MDTE must also approve the Transaction and any retail rate changes resulting from the Transaction. The Applicants do not believe that any other regulatory filings are needed. Any regulatory orders with respect to the Transaction issued prior to the Commission's decision with respect to the Application will be submitted as part of Exhibit L.

(j) An explanation, with appropriate evidentiary support for such explanation (to be identified as Exhibit M to the application):

(1) Of how applicants are providing assurance that the proposed transaction will not result in cross-subsidization of a non-utility associate company or pledge or encumbrance of utility assets for the benefit of an associate company; or

(2) If no such assurance can be provided, an explanation of how such cross-subsidization, pledge, or encumbrance will be consistent with the public interest.

The Applicants have addressed cross-subsidization and pledges and encumbrances of assets in Section E of Part VI of this Application and in Exhibit M which is attached.

SECTION 204 APPLICATION

IX. SHORT-TERM DEBT AUTHORIZATION

Pursuant to Section 204 of the FPA, BECo requests authorization for the issuance of $655 million in short-term debt from the consummation of the Transaction, expected to be January 1, 2007, through December 31, 2008. The $655 million request is the aggregate of the requests made by BECo, Cambridge and Commonwealth in Docket Nos. ES06-33-000, ES06-32-000 and ES06-34-000, respectively, on April 5, 2006. The following table sets out for BECo, Cambridge and Commonwealth the authorizations requested in the April 5, 2006 filing:

Company	Authorization Amount	Authorization Period	Docket Number
BECo	$450 Million	01/01/2007 thru 12/31/2008	ES06-33-000
Cambridge	$80 Million	06/27/2006 thru 06/26/2008	ES06-32-000
Commonwealth	$125 Million	12/01/2006 thru 11/30/2008	ES06-34-000

The effect of the completion of the Transaction and the merger of Cambridge and Commonwealth into BECo will be to extinguish the existing Cambridge and Commonwealth short-term debt authorizations. As indicated in the above table, the requested increased BECo authorization to $655 million would be intended to give BECo short-term debt authorization to provide for the combined needs of the current BECo/Cambridge/Commonwealth system. Thus, the new short-term debt authorization for BECo, as expanded to subsume its own operations and the operations of Cambridge and Commonwealth, will equal the aggregate authorization for BECo, Cambridge and Commonwealth as separate corporate entities and will be effective for approximately a two-year period ending December 31, 2008.

BECo will use the funds subject to this authorization request to conduct its public utility operations, including those now performed by Cambridge, Commonwealth and Canal. These operations are lawful and they are necessary for the protection of the public health, convenience and necessity. The financing will not impair BECo's ability to conduct these operations, and, in fact, without the financing authority requested herein, BECo's ability to fulfill its public utility responsibilities would be diminished. Otherwise, BECo relies on the submission in the April 5, 2006 filings in Docket Nos. ES06-33-000, ES06-32-000 and ES06-34-000 and requests such waivers of the Commission's regulations as may be necessary to accommodate the requested increase in its short-term debt issuance authority and, to the extent necessary, incorporation by reference of the April 5, 2006 filings as part of this filing.

X. EXPEDITIOUS CONSIDERATION

In accordance with Section 33.11 of the Commission's regulations, the Applicants submit that the Transaction is eligible for expeditious consideration pursuant to the provisions of Section 33.11 of the Commission's regulations. The Transaction is internal to the NSTAR corporate family, and thus has no impact on competition and does not require a competitive analysis. The transmission facilities BECo is acquiring pursuant to the terms of the Transaction are controlled by ISO-NE, a Commission approved RTO. The Transaction is subject to the approval of the MDTE and thus does not raise any concerns that cannot be addressed by the MDTE. As shown hereinabove, the Transaction is free of adverse effects on competition, rates, and regulation, does not result in prohibited cross-subsidies or asset encumbrances, and is thus consistent with the public interest. Accordingly, the Applicants ask that the Application be given expedited consideration, that public notice of the Application be issued within twenty-one days of the filing and that the Commission issue an order approving the Transaction within a two-month period or as soon thereafter as possible.

XI. MISCELLANEOUS

A. Section 33.5

The accounting information required by Section 33.5 of the Commission's regulations is contained in Attachment 2.

B. Section 33.6

A draft notice for publication in the Federal Register which briefly summarizes the facts of the Transaction is attached as Attachment 4 hereto. As required by Section 33.6, an electronic version of the draft notice is also submitted on 3 1/2" diskette.

C. Section 33.7

The Application includes as Attachment 3 the verification required by Section 33.7 of the Commission's regulations.

D. Service

The Applicants, electronically where possible and by first-class mail where not, have served a copy of this Application, including all attached materials, on the Governor and the Attorney General of the Commonwealth of Massachusetts, the MDTE, the ISO-NE, and the Applicants' local wholesale transmission, distribution and interconnection customers. The list of recipients is included as Attachment 5 hereto.

E. Closing Date

The Applicants intend to close on the Transaction on January 1, 2007 or as soon as possible thereafter effective as of January 1, 2007. They will advise the Commission of the actual closing date promptly upon its occurrence.

CONCLUSION

The Applicants jointly request the Commission to find that the Transaction will not have an adverse effect on competition, regulation or rates, and that this Application will fulfill all applicable requirements for authorization of the Transaction under Section 203 of the FPA and Part 33 of the Commission's regulations.

The Applicants also request the following actions:

a. Approval of the Transaction, to the full extent required by the FPA, and any other authorizations or approvals incidental thereto that may be required;

b. Approval of the Transaction on the Application and pleadings, without hearing; and

c. If a hearing is found to be necessary, institution of procedures (such as a paper hearing) that would permit the approval of the Transaction to be granted as expeditiously as possible.

The proposed Transaction plainly meets all of the Commission's requirements for approval. There is no change in market concentration and no anticompetitive effect of any kind. Ratepayers will incur savings in excess of any transaction or transition costs. The existing regulation of the Applicants' operations will be enhanced rather than diminished. The Transaction also does not result in a prohibited cross-subsidy or asset pledge or encumbrance. Therefore, on the basis of those considerations and all the considerations and circumstances set forth above, the Applicants request that the Commission approve the Transaction without hearing and within the sixty day period contemplated by the Commission's regulations for transactions that raise no substantive issues and no anticompetitive concerns, and are manifestly "consistent with the public interest." In addition, as set forth above, BECo asks the Commission for authorization to issue short-term debt in the amount of $655 million, as requested in Docket Nos. ES06-33-000, ES06-32-000 and ES06-34-000, for BECo, Cambridge and Commonwealth combined, with the authorization to be effective on and after the date of consummation of the Transaction through December 31, 2008.

Respectfully submitted,

Neven Rabadjija / RTS

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Counsel for Boston Edison Company,
Cambridge Electric Light Company,
Commonwealth Electric Company and
Canal Electric Company

May 26, 2006

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EXHIBIT A

APPLICANTS' BUSINESS ACTIVITIES

The Applicants' public utility operations are described in the Application. *See* Parts II and III, Pages 3-7. Each Applicant is a public utility under Part II of the FPA. NSTAR, which is a party to the Transaction, is currently an exempt public utility holding company under PUHCA. Exhibit B identifies each of the Applicants' affiliates and describes their respective business activities.

EXHIBIT B

APPLICANTS' ENERGY SUBSIDIARIES AND AFFILIATES

Exhibit B-1 provides the reference information for both energy and non-energy affiliates of the Applicants. Energy-related affiliates are identified by asterisk.

EXHIBIT B-1

APPLICANTS' ENERGY AND NON-ENERGY SUBSIDIARIES AND AFFILIATES

Name	*Principal Line(s) of Business*
Advanced Energy Systems, Inc.* ("AES")	Owner of MATEP
Medical Area Total Energy Plant, Inc. ("MATEP")*	Owns an 88 MW cogeneration facility; sells electricity, steam and chilled water to MATEP L.L.C.
MATEP L.L.C.*	Sells MATEP output to Harvard affiliated hospitals and schools
NSTAR Gas Company*	Provides local gas distribution service to approximately 300,000 customers principally in Cambridge, Somerville, Plymouth, New Bedford and Worcester and surrounding communities in Massachusetts
Hopkinton LNG Corp.*	Owns an LNG facility at Hopkinton, MA and an LNG storage facility in Acushnet, MA; product principally sold to NSTAR Gas Company
Harbor Energy Electric Company	Delivers electric energy from BECo to the Massachusetts Water Resources Authority through an underwater 115 kV cable
NSTAR Communications, Inc.	Provides data and dark fiber communications products
NSTAR Electric & Gas Corporation	Service company which provides common employees and other services for the Applicants
BEC Funding LLC	Special Purpose Entity (SPE) for securitizing Boston Edison's 1999 transition property.
BEC Funding II	SPE for securitizing Boston Edison's 2005 transition property
CEC Funding LLC	SPE for securitizing Commonwealth's 2005 transition property

*Energy-related affiliate

EXHIBIT C

ORGANIZATIONAL CHARTS

The Transaction does not affect the corporate structure of NSTAR except that BECo acquires Cambridge, Commonwealth and Canal which cease to exist. Exhibits C-1 and C-2 show the pre- and post-Transaction organizational charts.

EXHIBIT C-1

PRE-TRANSACTION ORGANIZATIONAL STRUCTURE

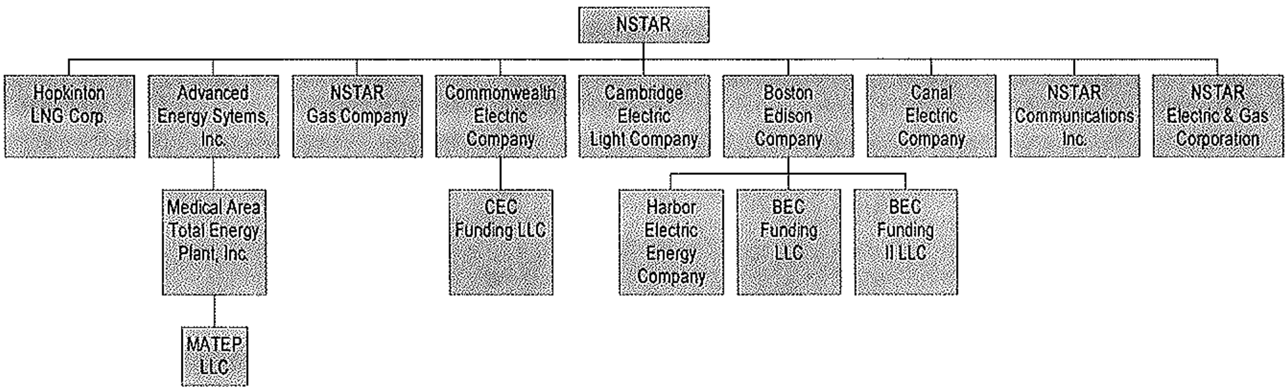

EXHIBIT C-2

POST-TRANSACTION ORGANIZATIONAL STRUCTURE

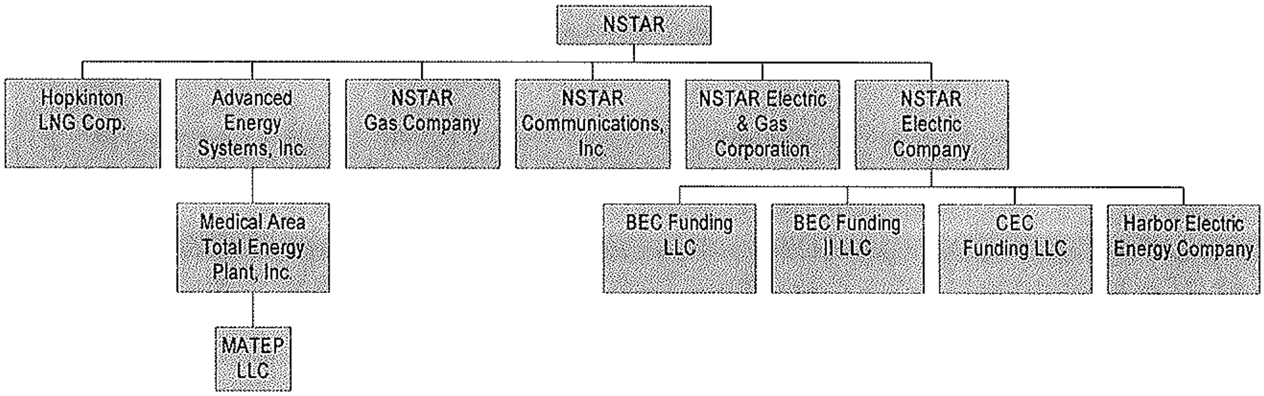

EXHIBIT D

APPLICANTS' JOINT VENTURES AND SIMILAR ARRANGEMENTS

The Transaction does not affect NSTAR's business interests, which remain the same before and after the Transaction. *See* Exhibits A-C. *See also* Parts I, II, and III of the Application, Pages 3-7. The Applicants only joint ventures or similar arrangements include their participation in the regional transmission organization for New England, the Hydro-Quebec project, and the Massachusetts, Maine and Connecticut Yankee nuclear power plants which have been retired but which continue to be active for decommissioning purposes.

EXHIBIT E

APPLICANTS' COMMON OFFICERS AND DIRECTORS

As affiliates, the Applicants have common officers and directors as shown on Exhibit E-1.

Exhibit E-1

Common Officers and Directors of NSTAR and Applicants

<u>NSTAR</u>

Chairman, President and Chief Executive Officer	Thomas J. May
Senior Vice President/Strategy, Law & Policy, Secretary/Clerk and General Counsel	Douglas S. Horan
Senior Vice President, Treasurer and Chief Financial Officer	James J. Judge
Senior Vice President – Human Resources	Timothy R. Manning
Senior Vice President – Customer & Corporate Relations	Joseph R. Nolan, Jr.
Senior Vice President – Operations	Werner J. Schweiger
Senior Vice President – Information Technology	Eugene J. Zimon
Vice President, Controller and Chief Accounting Officer	Robert J. Weafer, Jr.
Assistant Treasurer	Donald Anastasia
Assistant Treasurer	Philip J. Lembo
Assistant Secretary	Richard J. Morrison

<u>Trustee</u>

Thomas J. May

Boston Edison Company
Cambridge Electric Light Company
Canal Electric Company
Commonwealth Electric Company

Chairman, President and Chief Executive Officer	Thomas J. May
Senior Vice President/Strategy, Law & Policy and General Counsel	Douglas S. Horan
Senior Vice President, Treasurer and Chief Financial Officer	James J. Judge
Senior Vice President – Human Resources	Timothy R. Manning
Senior Vice President – Customer & Corporate Relations	Joseph R. Nolan, Jr.
Senior Vice President – Operations	Werner J. Schweiger
Senior Vice President – Information Technology	Eugene J. Zimon
Vice President, Controller and Chief Accounting Officer	Robert J. Weafer, Jr.
Assistant Treasurer	Donald Anastasia
Assistant Treasurer	Philip J. Lembo
Clerk	Richard J. Morrison

Directors

Douglas S. Horan

Thomas J. May

James J. Judge

EXHIBIT F

WHOLESALE POWER SALES AND UNBUNDLED TRANSMISSION SERVICES

1. The Applicants will have no wholesale power sales requirements customers.

2. The following entities are unbundled wholesale transmission customers of the Applicants; the Towns of Concord, Wellesley, and Belmont, Massachusetts; the Massachusetts Bay Transportation Authority at several locations throughout the greater Boston area and in Kingston, MA; Massachusetts Port Authority for service to several locations, including Logan International Airport and Hanscom Air Force Base; New England Power Company for service to Nantucket, MA; Entergy Nuclear Generation Company for service to the Pilgrim Nuclear Plant in Plymouth, MA; Mirant Americas Energy Marketing, LP to serve its Kendall Station in Cambridge, MA; and Mirant Canal, LLC to serve its diesel generators located on Martha's Vineyard, Massachusetts.

3. The following entities are wholesale generators that are connected to the Applicants' systems:

Wholesale Generator	***Location***
Entergy – Pilgrim	Plymouth, MA
Mirant – Canal	Sandwich, MA
Mirant – Kendall	Cambridge, MA
Mirant – Martha's Vineyard	Oak Bluffs & West Tisbury, MA
SEMASS	Rochester, MA
Dartmouth Power	Dartmouth, MA
Mystic Units 7, 8, 9	Everett, MA
New Boston	Boston, MA
L Street Jets	Boston, MA
Fore River Development	Weymouth, MA
Medway Jets	Medway, MA
Framingham Jets	Framingham, MA
MATEP	Boston, MA
MBTA Jets	Boston, MA
ANP Blackstone	Blackstone, MA
Northeast Energy Associates	Bellingham, MA

EXHIBIT G

APPLICANTS' JURISDICTIONAL FACILITIES

The Applicants' jurisdictional facilities are described in Exhibits G-1, G-2 and G-3.

EXHIBIT G-1

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Boston Edison Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Overhead:							
2	West Medway Station #446	West Medway	345.00	345.00	Steel	0.10		1
3	Holbrook Station #478	West Walpole Station #447	345.00	345.00	Steel	14.61		1
4	West Medway Station #446	West Walpole Station #447	345.00	345.00	Steel	9.62		1
5	West Walpole Station #447	West Walpole	345.00	345.00	Steel		0.65	1
6	West Medway Station #446	West Walpole	345.00	345.00	Steel		8.93	1
7	Whitman Station #451	Holbrook Station #478	345.00	345.00	Steel	7.30		1
8	Woburn Station #211	Billerica line	345.00	345.00	Wood	6.18		1
9	Pilgrim Station #650	Plymouth	345.00	345.00	Steel	7.30		1
10	Pilgrim Station #650	Plymouth	345.00	345.00	Steel		7.29	1
11	Plymouth	Whitman Station #451	345.00	345.00	Steel	25.85		1
12	West Medway Station #446	West Walpole Station #447	345.00	345.00	Wood	9.57		1
13	West Medway Station #446	Milford	345.00	345.00	Wood	1.83		1
14	Woburn Station #211	Lexington Station #320	345.00	345.00	Wood	8.24		1
15	West Medway Station #446	Milford	345.00	345.00	Wood	1.83		1
16	Bellingham Tap 336	Northeast Energy Associates	345.00	345.00	Wood	0.05		1
17	West Medway Station #446	Leland Street Station #240	230.00	230.00	Steel/	10.39		
18					Wood	0.57		1
19	West Medway Station #446	Waltham Station #282	230.00	230.00	Steel		17.58	
20					Wood	7.26		1
21	West Medway Station #446	Blackstone Station #309	345.00	345.00	Wood	7.86		1
22	Blackstone Station #309	Mass/ R. I. Line	345.00	345.00	Wood	11.04		1
23	Various Locations	Various Locations	115.00	115.00	Steel/Wood	159.90	36.11	33
24								
25	Underground:							
26	No. Cambridge Station #509	Woburn Station #211	345.00	345.00	Underground	12.04		2
27	Everett Station #250	No. Cambridge Station #509	345.00	345.00	Underground	9.92		2
28	Everett Station #250	Saugus NEES Sta. #90	345.00	345.00	Underground	6.29		1
29	Everett Station #250	Boston Station #514	345.00	345.00	Underground	8.40		2
30	Various Locations	Various Locations	115.00	115.00	Underground	134.64		27
31	Milford Station #479	Hopkinton Station #126	115.00	115.00	Underground	1.28		1
32	Milford Station #479	Hopkinton Station #126	115.00	115.00	Underground	1.28		1
33								
34	Transmission line rents							
35	(A/C 567)							
36					TOTAL	463.35	70.56	88

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Boston Edison Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
								1
Alum.2-900		30,064	30,064					2
ACSR2-1590		4,523,351	4,523,351					3
ACSR 2500		1,552,169	1,552,169					4
ACSR 2500		161,208	161,208					5
ACAR 2-1703		1,277,543	1,277,543					6
ACSR 2-1590	950,810	5,128,417	6,079,227					7
ACSR 2-954		1,600,760	1,600,760					8
ACAR 2-1703	666,198	3,824,349	4,490,547					9
ACAR 2-1703								10
ACSR 2-1590	1,619,692	7,705,518	9,325,210					11
ACSR 2-954		1,369,370	1,369,370					12
Alum. 2-900		486,255	486,255					13
ACSR 2-1113		4,734,001	4,734,001					14
ACSR 2-1113		1,764,971	1,764,971					15
ACAR 2-1024								16
								17
ACSR 1113		887,788	887,788					18
								19
ACSR 1113	100,775	2,805,256	2,906,031					20
ACSS 2-900	514,000	2,051,400	2,565,400					21
ACSS 2-900	756,500	2,308,500	3,065,000					22
Various	4,861,883	39,380,052	44,241,935					23
				6,163,522	1,994,373		8,157,895	24
								25
CU-2-2500	1,610	14,805,078	14,806,688					26
CU-2500	2,756	14,889,557	14,892,313					27
CU-2-2500		22,295,501	22,295,501					28
CU-2500		25,523,693	25,523,693					29
Various	93,426	78,642,416	78,735,842					30
750KCMIL	48,450	1,674,991	1,723,441					31
750KCMIL	48,450	1,674,991	1,723,441					32
				4,059,265	675,422		4,734,687	33
						9,505,842	9,505,842	34
								35
	9,664,550	241,097,199	250,761,749	10,222,787	2,669,795	9,505,842	22,398,424	36

EXHIBIT G-2

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cambridge Electric Light Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	W. Cambridge-Atewife (Bulk)	Putnam Avenue (Bulk)	115.00	115.00	Underground	7.30		2
2	Putnam Substation	Kendall Station	115.00	115.00	Underground	2.50		1
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
17								
18								
19								
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	9.80		3

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cambridge Electric Light Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
2000 Cu		11,744,043	11,744,043					1
3200 Cu XLPE		9,946,678	9,946,678					2
								3
								4
								5
								6
								7
								8
								9
								10
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								12
								13
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								16
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								18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
		21,690,721	21,690,721					36

EXHIBIT G-3

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Commonwealth Electric Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	Cape Cod Canal Crs 108/113	Cape Cod Canal Crossing	115.00	115.00	Steel Tower	1.00		2
2	Bourne 108	Horse Pond Tap 108	115.00	115.00	H Frame	1.90		1
3	Horse Pond Tap 108	Wareham Tap	115.00	115.00	H Frame	5.40		1
4	WareHampt 108	Tremont	115.00	115.00	H Frame	3.90		1
5	Horse Pond Tap 108	Manomet	115.00	115.00	Steel/Wood	12.10		1
6	High Hill 109	Cross Road 109	115.00	115.00	H Frame	4.10		1
7	Cross Road 109	Fisher	115.00	115.00	H Frame	4.40		1
8	Industrial Park 111	High Hill	115.00	115.00	H Frame	2.40		1
9	High Hill 111	Dartmouth Pwr Tap	115.00	115.00	H Frame	2.70		1
10	Dartmouth Pwr Tap 111	Cross Road 111	115.00	115.00	H Frame	1.40		1
11	Tremont 112	Rochester 112	115.00	115.00	H Frame	6.70		1
12	Rochester 112	Industrial Park Tap	115.00	115.00	H Frame	3.60		1
13	Industrial Park Tap	Wing Lane 112	115.00	115.00	H Frame	1.30		1
14	Wing Lane 112	Acushnet	115.00	115.00	H Frame	1.10		1
15	Industrial Park Tap 112	Industrial Park	115.00	115.00	H Frame	4.10		1
16	Wing Lane 112	Arsene	115.00	115.00	W Monopole	4.20		1
17	Achusnet 112	Pine St.	115.00	115.00	Undergr cable	4.20		1
18	Acushnet 114	Pine St.	115.00	115.00	Undergr cable	4.20		1
19	Bourne 113	Horse Pond Tap 113	115.00	115.00	H Frame	1.90		1
20	Horse Pond Tap 113	Valley TP	115.00	115.00	H Frame	0.70		1
21	Valley TP 113	Wareham 113	115.00	115.00	H Frame	4.70		1
22	Wareham 113	Tremont	115.00	115.00	H Frame	3.90		1
23	Tremont 114	Rochester 114	115.00	115.00	S Monopole	6.70		1
24	Rochester 114	Crystal Spring Tap	115.00	115.00	S Monopole	3.50		1
25	Crystal Spring Tap 114	Wing Lane	115.00	115.00	S Monopole	1.40		1
26	Wing Lane 114	Acushnet	115.00	115.00	S Monopole	1.10		1
27	Crystal Spring Tap 114	Crystal Springs	115.00	115.00	S Monopole	2.90		1
28	Bourne 107	Otis	115.00	115.00	H Frame	3.40		1
29	Otis 107	Falmouth Tap	115.00	115.00	H Frame	6.60		1
30	Falmouth Tap 107W	Falmouth	115.00	115.00	H Frame	5.20		1
31	Falmouth Tap 115E	Falmouth	115.00	115.00	H Frame	5.20		1
32	Falmouth Tap 115	Hatchville	115.00	115.00	H Frame	2.50		1
33	Hatchville 115	Mashpee	115.00	115.00	H Frame	5.20		1
34	Mashpee 115	Barnstable	115.00	115.00	H Frame	12.30		1
35	Carver 116	Brook Street	115.00	115.00	S Monopole	4.90		1
36					TOTAL	346.28		77

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Commonwealth Electric Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of
	From (a)	To (b)	Operating (c)	Designed (d)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	Circuits (h)
1	Brook Street 116	West Pond 116	115.00	115.00	H Frame	4.90		1
2	Brook Street117	Kingston	115.00	115.00	H Frame	3.10		1
3	Brook Street117	West Pond 117	115.00	115.00	H Frame	4.90		1
4	Kingston 117	Duxbury 117	115.00	115.00	H Frame	4.40		1
5	Barnstable 118	Harwich Tap	115.00	115.00	H Frame	7.20		1
6	Barnstable 119	Hyannis GE3 Tap to Dennis T	115.00	115.00	H Frame	7.20		1
7	Harwich Tap 118	Harwich	115.00	115.00	W Monopole	4.40		1
8	Harwich Tap 118	Orleans	115.00	115.00	W Monopole	9.60		1
9	Orleans 125	Wellfleet	115.00	115.00	H Frame	13.10		1
10	Dennis Tap 199	Harwich	115.00	115.00	H Frame	4.40		1
11	Harwich Tap 119	Orleans	115.00	115.00	W Monopole	9.60		1
12	Canal 120/342	Bourne (portion)	115.00	345.00	S Lattice	2.50		2
13	Bourne (portion) 120	Barnstable	115.00	345.00	S Monopole	2.50		1
14	Canal 121	Bourne	115.00	115.00	S Monopole	2.50		1
15	Bourne 122	Pave Paws	115.00	115.00	S Monopole	1.20		1
16	Pave Paws 122	Sandwich	115.00	115.00	S Monopole	5.70		1
17	Sandwich 122	Oak Street	115.00	115.00	S Monopole	5.90		1
18	Oak Street 122	Barnstable	115.00	115.00	S Monopole	3.80		1
19	Hyannis GE3 Tap 123	Hyannis GE3	115.00	115.00	H Frame	1.00		1
20	Barnstable 124	Hyannis GE2	115.00	115.00	H Frame	1.00		1
21	Canal 126	Bourne	115.00	115.00	S Lattice	2.78		1
22	Semass Tap 127	Carver	115.00	115.00	S Monopole	7.30		1
23	Tremont 128	Semass Tap	115.00	115.00	S Monopole	1.00		1
24	Semass Tap 129	Semass	115.00	115.00	S Monopole	0.50		1
25	Kingston 191	Auburn St	115.00	115.00	H Frame	15.30		1
26	Kingston 191	Duxbury 191	115.00	115.00	H Frame	4.40		1
27	Duxbury 191	Marshfield	115.00	115.00	H Frame	2.30		1
28	High Hill D21	Bell Rock Rd	115.00	115.00	H Frame	5.30		1
29	Canal 322	Myles Standish Tap	345.00	345.00	H Frame	13.10		1
30	Myles Standish Tap 322	Carver	345.00	345.00	H Frame	7.20		1
31	Carver 331	Bridgewater	345.00	345.00	H Frame	9.40		1
32	Canal	Myles Standish Tap	345.00	345.00	S Lattice	13.10		1
33	Cape Cod Canal Cr 343/322	Cape Cod Canal Crossing	345.00	345.00	S Lattice	1.00		2
34	Myles Standish Tap 355	Middleborough	345.00	345.00	S Lattice	8.30		1
35	Middleborough 355	Bridgewater	345.00	345.00	S Lattice	8.30		1
36					TOTAL	346.28		77

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Commonwealth Electric Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	W. Medway 336	NEA Tap	345.00	345.00	H Frame	1.10		1
2	NEA Tap 336	ANP Blackstone	345.00	345.00	H Frame	0.50		1
3	ANP Blackstone 336	Sherman Road	345.00	345.00	H Frame	2.10		1
4	Pine St 130	Acushnet 130	115.00	115.00	Underground	3.60		1
5								
6	Total All Lines					346.28		77
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
17								
18								
19								
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	346.28		77

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Commonwealth Electric Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
795	12,027	147,275	159,302					1
795	8,999	74,430	83,429					2
795	25,575	211,528	237,103					3
795	18,472	152,789	171,261					4
795	192,992	720,025	913,017					5
4/0	52,022	238,729	290,751					6
4/0	55,828	256,197	312,025					7
795	89,277	219,148	308,425					8
795	18,648	234,171	252,819					9
795	9,669	121,422	131,091					10
795	33,497	170,320	203,817					11
795	17,999	91,516	109,515					12
795	7,310	74,095	81,405					13
795	6,186	62,695	68,881					14
795		51,732	51,732					15
795	36,054	367,867	403,921					16
250CU	101	939,981	940,082					17
250CU	101	939,980	940,081					18
795	8,407	48,979	57,386					19
795	3,097	18,045	21,142					20
795	20,884	121,673	142,557					21
795	17,167	100,019	117,186					22
2338	20,110	2,336,441	2,356,551					23
2338	10,505	1,220,529	1,231,034					24
2338	4,292	498,673	502,965					25
2338	3,212	373,133	376,345					26
4/0	63,132	213,811	276,943					27
2338		25,429	25,429					28
1590		49,362	49,362					29
4/0	32,155	264,643	296,798					30
795	32,165	285,591	317,756					31
795	62,943	195,520	258,463					32
795	130,921	406,681	537,602					33
795	308,672	958,830	1,267,502					34
2338		3,165,770	3,165,770					35
	3,550,816	68,207,549	71,758,365	263,504	692,833		956,337	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Commonwealth Electric Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
795	26,909	128,154	155,063					1
336	10,917	66,027	76,944					2
4/0	30,721	239,965	270,686					3
795	30,421	523,703	554,124					4
795	308,743	1,115,493	1,424,236					5
795	80,255	309,871	390,126					6
795		1,739,526	1,739,526					7
795	69,886	1,242,893	1,312,779					8
4/0	141,089	347,799	488,888					9
4/0	31,333	213,752	245,085					10
795		3,245,473	3,245,473					11
2-1703	22,555	324,048	346,603					12
2-1703		8,797,124	8,797,124					13
2338	23,848	1,715,907	1,739,755					14
2-1703	8,107	562,178	570,285					15
2-1703	39,703	2,753,231	2,792,934					16
2-1703	41,157	2,854,135	2,895,292					17
2338	26,399	1,830,682	1,857,081					18
795		11,271	11,271					19
4/0	61,839	7,751	69,590					20
2338ACAR		1,452,187	1,452,187					21
2338		5,265,824	5,265,824					22
2338		681,901	681,901					23
795								24
336	147,690	1,332,331	1,480,021					25
4/0	106,392	222,464	328,856					26
4/0	55,983	117,060	173,043					27
795	24,566	76,656	101,222					28
2335	135,401	1,017,104	1,152,505					29
2335	74,661	560,840	635,501					30
2335	97,246	730,486	827,732					31
2-1703	142,475	2,268,899	2,411,374					32
2-1703	2,337	157,094	159,431					33
2-1703	93,607	1,568,012	1,661,619					34
2-1703	93,505	1,566,316	1,659,821					35
	3,550,816	68,207,549	71,758,365	263,504	692,833		956,337	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Commonwealth Electric Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2005	End of 2005/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent s not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
2-900	95,422	191,491	286,913					1
2-1024+2-901	42,983	86,257	129,240					2
2-1024+2-902	182,247	365,730	547,977					3
1000 Copper		7,160,885	7,160,885					4
				263,504	692,833		956,337	5
	3,550,816	68,207,549	71,758,365	263,504	692,833		956,337	6
								7
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								34
								35
	3,550,816	68,207,549	71,758,365	263,504	692,833		956,337	36

EXHIBIT H

AFFECTED FACILITIES AND SECURITIES

The jurisdictional facilities associated with the Transaction are described in Exhibit G. There will be no change in the status of those facilities as a consequence of the Transaction except that BECo will acquire the facilities now owned by Commonwealth and Cambridge. The outstanding long-term debt securities of Cambridge and Commonwealth will be redeemed. Otherwise, the Transaction will not affect any publicly held securities.

EXHIBIT I

TRANSACTION DOCUMENTS

The documents to effectuate the Transaction are attached.

EXHIBIT I-1

CAMBRIDGE ELECTRIC LIGHT COMPANY

CERTIFIED VOTES OF DIRECTORS

CAMBRIDGE ELECTRIC LIGHT COMPANY

Certified Votes of Directors

VOTED: That the Company merge into Boston Edison Company effective upon the receipt of approval of the sole stockholder of the Company, and all necessary governmental approvals, and upon proper filing with the Secretary of the Commonwealth of Massachusetts.

VOTED: That the Agreement and Plan of Merger (the "Merger Agreement") among the Company, Commonwealth Electric Company, Canal Electric Company and Boston Edison Company, in substantially the form previously submitted to the Directors of the Company, pursuant to which the Company will be merged with and into Boston Edison Company and the 360,000 shares of the Company's common stock exchanged for an equal number of shares of Boston Edison Company, be and it hereby is authorized, adopted and approved, and that either the Chairman, President and Chief Executive Officer or the Senior Vice President, Treasurer and Chief Financial Officer (the "Authorized Officers") hereby be authorized to execute the Merger Agreement, with such changes as the officer or officers may deem necessary or advisable, and to take such additional action which either of them may deem necessary or advisable to consummate the merger and perform the Company's obligations under the Merger Agreement.

VOTED: That each of the Authorized Officers is authorized in the name and behalf of the Company to file with the Massachusetts Department of Telecommunications and Energy, the Federal Energy Regulatory Commission and any other Federal, state or municipal governmental agencies, applications for all necessary approvals for the merger of the Company and the transactions contemplated thereby and by the Merger Agreement, including an application to the Federal Energy Regulatory Commission under Section 203 of the Federal Power Act for Boston Edison Company to acquire the owned jurisdictional facilities of the Company, together with such related matters as the Authorized Officers filing same shall deem appropriate or advisable, and that such Authorized Officers be and hereby are authorized to take such further actions in connection with such applications as the officer or officers so acting may deem necessary, appropriate or advisable.

VOTED: That all assets, property, contracts, agreements, bank accounts and other assets and liabilities of the Company shall become the assets, property, contracts, agreements, bank accounts, and other assets and liabilities of Boston Edison Company upon the effective date of the merger of the Company into Boston Edison Company.

<u>VOTED</u>: That the proper officers of this Company be, and they hereby are authorized, empowered and directed, in its name and on its behalf to execute and deliver such agreements, instruments, filings, notices, documents, requests, consents, approvals and applications for regulatory approval and to do any and all other acts and things necessary and proper to accomplish and carry out the purposes of the foregoing votes.

THIS IS TO CERTIFY that the undersigned is Assistant Secretary of CAMBRIDGE ELECTRIC LIGHT COMPANY, a corporation of the Commonwealth of Massachusetts; that the above and foregoing is a true and correct copy of votes adopted by the Board of Directors of said Corporation at a special meeting thereof duly convened and held on the 6th day of April, 2006, at which meeting the entire Board was present and voting; and that said votes have not been annulled, revoked or amended in any way whatsoever, but are in full force and effect.

WITNESS the execution hereof as a sealed instrument this 19th day of May, 2006.

Ellen J. Lucero
Assistant Secretary

EXHIBIT I-2

COMMONWEALTH ELECTRIC COMPANY

CERTIFIED VOTES OF DIRECTORS

COMMONWEALTH ELECTRIC COMPANY

Certified Votes of Directors

VOTED: That the Company merge into Boston Edison Company effective upon the receipt of approval of the sole stockholder of the Company, and all necessary governmental approvals, and upon proper filing with the Secretary of the Commonwealth of Massachusetts.

VOTED: That the Agreement and Plan of Merger (the "Merger Agreement") among the Company, Cambridge Electric Light Company, Canal Electric Company and Boston Edison Company, in substantially the form previously submitted to the Directors of the Company, pursuant to which the Company will be merged with and into Boston Edison Company and the 2,043,972 shares of the Company's common stock exchanged for an equal number of shares of Boston Edison Company, be and it hereby is authorized, adopted and approved, and that either the Chairman, President and Chief Executive Officer or the Senior Vice President, Treasurer and Chief Financial Officer (the "Authorized Officers") hereby be authorized to execute the Merger Agreement, with such changes as the officer or officers may deem necessary or advisable, and to take such additional action which either of them may deem necessary or advisable to consummate the merger and perform the Company's obligations under the Merger Agreement.

VOTED: That each of the Authorized Officers is authorized in the name and behalf of the Company to file with the Massachusetts Department of Telecommunications and Energy, the Federal Energy Regulatory Commission and any other Federal, state or municipal governmental agencies, applications for all necessary approvals for the merger of the Company and the transactions contemplated thereby and by the Merger Agreement, including an application to the Federal Energy Regulatory Commission under Section 203 of the Federal Power Act for Boston Edison Company to acquire the owned jurisdictional facilities of the Company, together with such related matters as the Authorized Officers filing same shall deem appropriate or advisable, and that such Authorized Officers be and hereby are authorized to take such further actions in connection with such applications as the officer or officers so acting may deem necessary, appropriate or advisable.

VOTED: That all assets, property, contracts, agreements, bank accounts and other assets and liabilities of the Company shall become the assets, property, contracts, agreements, bank accounts, and other assets and liabilities of Boston Edison Company upon the effective date of the merger of the Company into Boston Edison Company.

VOTED: That the proper officers of this Company be, and they hereby are authorized, empowered and directed, in its name and on its behalf to execute and deliver such agreements, instruments, filings, notices, documents, requests, consents, approvals and applications for regulatory approval and to do any and all other acts and things necessary and proper to accomplish and carry out the purposes of the foregoing votes.

THIS IS TO CERTIFY that the undersigned is Assistant Secretary of COMMONWEALTH ELECTRIC COMPANY, a corporation of the Commonwealth of Massachusetts; that the above and foregoing is a true and correct copy of votes adopted by the Board of Directors of said Corporation at a special meeting thereof duly convened and held on the 6th day of April, 2006, at which meeting the entire Board was present and voting; and that said votes have not been annulled, revoked or amended in any way whatsoever, but are in full force and effect.

WITNESS the execution hereof as a sealed instrument this 19th day of May, 2006.

Assistant Secretary

EXHIBIT I-3

CANAL ELECTRIC COMPANY

CERTIFIED VOTES OF DIRECTORS

CANAL ELECTRIC COMPANY

Certified Votes of Directors

VOTED: That the Company merge into Boston Edison Company effective upon the receipt of approval of the sole stockholder of the Company, and all necessary governmental approvals, and upon proper filing with the Secretary of the Commonwealth of Massachusetts.

VOTED: That the Agreement and Plan of Merger (the "Merger Agreement") among the Company, Cambridge Electric Light Company, Commonwealth Electric Company and Boston Edison Company, in substantially the form previously submitted to the Directors of the Company, pursuant to which the Company will be merged with and into Boston Edison Company and the 1,523,200 shares of the Company's common stock exchanged for an equal number of shares of Boston Edison Company, be and it hereby is authorized, adopted and approved, and that either the Chairman, President and Chief Executive Officer or the Senior Vice President, Treasurer and Chief Financial Officer (the "Authorized Officers") hereby be authorized to execute the Merger Agreement, with such changes as the officer or officers may deem necessary or advisable, and to take such additional action which either of them may deem necessary or advisable to consummate the merger and perform the Company's obligations under the Merger Agreement.

VOTED: That each of the Authorized Officers is authorized in the name and behalf of the Company to file with the Massachusetts Department of Telecommunications and Energy, the Federal Energy Regulatory Commission and any other Federal, state or municipal governmental agencies, applications for all necessary approvals for the merger of the Company and the transactions contemplated thereby and by the Merger Agreement, including an application to the Federal Energy Regulatory Commission under Section 203 of the Federal Power Act for Boston Edison Company to acquire the owned jurisdictional facilities of the Company, together with such related matters as the Authorized Officers filing same shall deem appropriate or advisable, and that such Authorized Officers be and hereby are authorized to take such further actions in connection with such applications as the officer or officers so acting may deem necessary, appropriate or advisable.

VOTED: That all assets, property, contracts, agreements, bank accounts and other assets and liabilities of the Company shall become the assets, property, contracts, agreements, bank accounts, and other assets and liabilities of Boston Edison Company upon the effective date of the merger of the Company into Boston Edison Company.

VOTED: That the proper officers of this Company be, and they hereby are authorized, empowered and directed, in its name and on its behalf to execute and deliver such agreements, instruments, filings, notices, documents, requests, consents, approvals and applications for regulatory approval and to do any and all other acts and things necessary and proper to accomplish and carry out the purposes of the foregoing votes.

THIS IS TO CERTIFY that the undersigned is Assistant Secretary of CANAL ELECTRIC COMPANY, a corporation of the Commonwealth of Massachusetts; that the above and foregoing is a true and correct copy of votes adopted by the Board of Directors of said Corporation at a special meeting thereof duly convened and held on the 6th day of April, 2006, at which meeting the entire Board was present and voting; and that said votes have not been annulled, revoked or amended in any way whatsoever, but are in full force and effect.

WITNESS the execution hereof as a sealed instrument this 17th day of May, 2006.

Eleanor J. Iacono

Assistant Secretary

EXHIBIT I-4

BOSTON EDISON COMPANY

CERTIFIED VOTES OF DIRECTORS

BOSTON EDISON COMPANY

Certified Votes of Directors

VOTED: That the Company merge with Cambridge Electric Light Company, Canal Electric Company and Commonwealth Electric Company, pursuant to an Agreement and Plan of Merger (the "Merger Agreement") authorized at this meeting, pursuant to which the affiliated electric utilities of the Company hereinafter named shall be merged into the Company, and the Company be the sole surviving corporation, effective upon the receipt of approval of the sole stockholder of the Company, and all necessary governmental approvals, and upon proper filing with the Secretary of the Commonwealth of Massachusetts.

VOTED: That the Merger Agreement among the Company, Cambridge Electric Light Company, Canal Electric Company and Commonwealth Electric Company, in substantially the form previously submitted to the Directors of the Company, be and it hereby is authorized, adopted and approved, and that either the Chairman, President and Chief Executive Officer or the Senior Vice President, Treasurer and Chief Financial Officer (the "Authorized Officers") hereby be authorized to execute the Merger Agreement, with such changes as the officer or officers may deem necessary or advisable, and to take such additional action which either of them may deem necessary or advisable to consummate the merger and perform the Company's obligations under the Merger Agreement.

VOTED: That each of the Authorized Officers is authorized in the name and behalf of the Company to file with the Massachusetts Department of Telecommunications and Energy, the Federal Energy Regulatory Commission and any other Federal, state or municipal governmental agencies, applications for all necessary approvals for the merger of the Company and the transactions contemplated thereby and by the Merger Agreement, including an application to the Federal Energy Regulatory Commission under Section 203 of the Federal Power Act for this Company acquire the owned jurisdictional facilities of Cambridge Electric Light Company, Canal Electric Company and Commonwealth Electric Company together with such related matters as the Authorized Officers filing same shall deem appropriate or advisable, and that such Authorized Officers be and hereby are authorized to take such further actions in connection with such applications as the officer or officers so acting may deem necessary, appropriate or advisable.

VOTED: That all assets, property, contracts, agreements, bank accounts and other assets and liabilities of Cambridge Electric Light Company, Canal Electric Company and Commonwealth Electric Company shall become the assets, property, contracts, agreements, bank accounts, and other assets and liabilities of this Company upon the effective date of the merger of this Company with Cambridge Electric Light Company, Canal Electric Company and Commonwealth Electric Company.

VOTED: That the proper officers of this Company be, and they hereby are authorized, empowered and directed, in its name and on its behalf to execute and deliver such agreements, instruments, filings, notices, documents, requests, consents, approvals and applications for regulatory approval and to do any and all other acts and things necessary and proper to accomplish and carry out the purposes of the foregoing votes.

THIS IS TO CERTIFY that the undersigned is Assistant Secretary of BOSTON EDISON COMPANY, a corporation of the Commonwealth of Massachusetts; that the above and foregoing is a true and correct copy of votes adopted by the Board of Directors of said Corporation at a special meeting thereof duly convened and held on the 6th day of April, 2006, at which meeting the entire Board was present and voting; and that said votes have not been annulled, revoked or amended in any way whatsoever, but are in full force and effect.

WITNESS the execution hereof as a sealed instrument this 19th day of May, 2006.

Ellen ? Dacew

Assistant Secretary

EXHIBIT I-5

AGREEMENT AND PLAN OF MERGER

AGREEMENT AND PLAN OF MERGER

AGREEMENT AND PLAN OF MERGER ("Agreement") dated as of April 10, 2006, by and among Boston Edison Company, a Massachusetts utility corporation ("Boston Edison"), Commonwealth Electric Company, a Massachusetts utility corporation ("CEC"), Cambridge Electric Light Company, a Massachusetts utility corporation ("Cambridge"), and Canal Electric Company, a Massachusetts utility corporation ("Canal").

WITNESSETH:

WHEREAS, Boston Edison has an authorized capitalization consisting of (i) 100,000,000 shares of common stock, par value $1.00 per share ("Boston Edison Common Stock"), of which 75 shares are issued and outstanding; (ii) 2,660,000 shares of cumulative preferred stock, par value $100.00 per share ("Boston Edison Preferred Stock"), 430,000 shares of which (consisting of shares of two separate series) are issued and outstanding; and (iii) 8,000,000 shares of preference stock, par value $1.00 per share ("Boston Edison Preference Stock"), of which no shares are issued and outstanding;

WHEREAS, CEC has an authorized capitalization consisting of) 2,043,972 shares of common stock, par value $1.00 per share ("CEC Common Stock"), all of which shares are issued and outstanding;

WHEREAS, Cambridge has an authorized capitalization consisting of 346,600 shares of common stock, par value $1.00 per share ("Cambridge Common Stock"), all of which shares are issued and outstanding;

WHEREAS, Canal has an authorized capitalization consisting of 1,523,000 shares of common stock, par value $1.00 per share ("Canal Common Stock"), all of which shares are issued and outstanding; and

WHEREAS, the Boards of Directors of the respective parties hereto deem it advisable and in the best interests of CEC, Cambridge and Canal, and their respective stockholders to merge CEC, Cambridge and Canal with and into Boston Edison (the "Merger") in accordance with Section 96 of Chapter 164 of the Massachusetts General Laws and pursuant to this Agreement and the Articles of Merger attached hereto as Annex I and incorporated herein (the "Articles"), whereby the holders of shares of CEC Common Stock, Cambridge Common Stock and Canal Common Stock will exchange their shares for Boston Edison Common Stock;

NOW, THEREFORE, in consideration of the premises and the representations, warranties and agreements herein contained, the parties hereto agree that CEC, Cambridge and Canal shall be merged with into Boston Edison, which shall be the corporation surviving the Merger, and that the terms and conditions of the Merger, the mode of carrying it into effect, and the manner of converting and exchanging shares shall be as follows:

ARTICLE I
THE MERGER

(a) Subject to and in accordance with the provisions of this Agreement, the Articles shall be executed and acknowledged by each of Boston Edison, CEC, Cambridge and Canal, and thereafter delivered to the Secretary of State of The Commonwealth of Massachusetts for filing, as provided in Section 102A of Chapter 164 of the Massachusetts General Laws. The Merger shall become effective at such time as the Articles are filed as required by law with the Secretary of State of The Commonwealth of Massachusetts or such date, not more than thirty days after such filing, as may be specified in the Articles (the "Effective Time"). At the Effective Time, the separate existence of each of CEC, Cambridge and Canal shall cease and CEC, Cambridge and Canal shall be merged with and into Boston Edison (CEC, Cambridge, Canal and Boston Edison being sometimes referred to collectively herein as the "Constituent Corporations" and Boston Edison, the corporation designated in the Articles as the surviving corporation being sometimes referred to herein as the "Surviving Corporation");

(b) Prior to and after the Effective Time, Boston Edison, CEC, Cambridge and Canal, respectively, shall take all such actions as may be necessary or appropriate in order to effectuate the Merger. In this connection, Boston Edison shall issue the Boston Edison Common Stock which the holders of CEC Common Stock, Cambridge Common Stock and Canal Common Stock are entitled to receive as provided in Article II hereof. In the event that at any time after the Effective Time any further action is necessary or desirable to carry out the purposes of this Agreement and to vest the Surviving Corporation with full title to all properties, assets, rights, approvals, immunities and franchises of any of the Constituent Corporations, the officers and directors of each of the Constituent Corporations as of the Effective Time shall take all such further action.

ARTICLE II
TERMS OF CONVERSION AND EXCHANGE OF SHARES

At the Effective Time:

(a) Each share of Boston Edison Common Stock issued and outstanding immediately prior to the Merger shall not be converted or otherwise affected by the Merger, and each such share shall continue to be issued and outstanding and to be one fully paid and nonassessable share of the common stock of the Surviving Corporation;

(b) The shares of Boston Edison Preferred Stock issued and outstanding immediately prior to the Merger shall not be converted or otherwise affected by the Merger, and each such share shall continue to be issued and outstanding and to be one fully paid and nonassessable share of the particular series of preferred stock of the Surviving Corporation; and

(c) Each share of CEC Common Stock, Cambridge Common Stock and Canal Common Stock issued and outstanding immediately prior to the Merger shall, by virtue of the Merger and without any action on the part of any holder thereof, be converted into the following number of share of common stock of the Surviving Corporation, which thereupon shall be issued, fully paid and nonassessable: 0.0000088 in the case of CEC; 0.0000115 in the case of Cambridge; and 0.0000084 in the case of Canal.

ARTICLE III
ARTICLES OF ORGANIZATION AND BYLAWS

From and after the Effective Time, and until thereafter amended as provided by law, the Restated Articles of Organization of Boston Edison as in effect immediately prior to the Merger shall be and continue to be the Restated Articles of Organization of the Surviving Corporation. The purposes of the Surviving Corporation, the total number of shares and par value of each class of stock which the Surviving Corporation is authorized to issue and a description of each class of stock authorized at the Effective Time, with the preferences, voting powers, qualifications, special or relative rights or privileges as to each class and any series thereof then established, are as stated in such Restated Articles of Organization, which are attached hereto as Annex II and incorporated herein. From and after the Effective Time, the Bylaws of Boston Edison shall be and continue to be the Bylaws of the Surviving Corporation until amended in accordance with law.

ARTICLE IV
DIRECTORS AND OFFICERS

The persons who are directors and officers of Boston Edison immediately prior to the Merger shall continue as directors and officers, respectively, of the Surviving Corporation and shall continue to hold office as provided in the Bylaws of the Surviving Corporation. If, at or following the Effective Time, a vacancy shall exist in the Board of Directors or in the position of any officer of the Surviving Corporation, such vacancy may be filled in the manner provided in the Bylaws of the Surviving Corporation.

ARTICLE V
STOCK CERTIFICATES

As soon as practicable after the Effective Time the holders of outstand shares of CEC Common Stock, Cambridge Common Stock and Canal Common Stock shall deliver to the Surviving Company such shares in exchange for the appropriate number of shares of common stock of the Surviving Company as provided in Article II. At the Effective Time, each outstanding certificate which, prior to the Effective Time, represented CEC Common Stock, Cambridge Common Stock and Canal Common Stock shall be no longer be outstanding and shall be automatically cancelled and each holder thereof will cease to have rights with respect thereto, except to receive the appropriate number of shares of common stock of the Surviving Company in accordance with Article II..

ARTICLE VI
CONDITIONS OF THE MERGER

Consummation of the Merger is subject to the satisfaction of the following conditions:

(a) The Merger shall have received the approval of the holders of each class of common stock outstanding and entitled to vote thereupon of each of the Constituent Corporations as required by Section 96 of Chapter 164 of the Massachusetts General Laws.

(b) The issuance of Boston Edison Common Stock and the Merger shall have been approved by the Massachusetts Department of Telecommunications and Energy as required by Chapter 164 of the Massachusetts General Laws, by the Federal Energy Regulatory Commission ("FERC") as required by Section 203 of the FERC's regulations and by all other governmental agencies whose approval is necessary, appropriate or desirable.

ARTICLE VII
AMENDMENT AND TERMINATION

The parties hereto by mutual consent of their respective Boards of Directors may amend, modify, supplement or terminate (and the Merger and other transactions herein provided for abandoned) this Agreement in such manner as may be agreed upon by them in writing, at any time before or after approval of this Agreement by the stockholders of the Constituent Corporations.

ARTICLE VIII
EFFECTIVE TIME OF THE MERGER

Subject to the prior satisfaction of the conditions of the Merger set forth in Article VI hereof and the authority to terminate this Agreement as set forth in Article VII hereof, the Constituent Corporations shall do all such acts and things as shall be necessary or desirable in order to make the Effective Time occur as soon thereafter as practicable.

ARTICLE IX
MISCELLANEOUS

This Agreement may be executed in counterparts, each of which when so executed shall be deemed to be an original, and such counterparts shall together constitute but one and the same instrument.

N WITNESS WHEREOF, Boston Edison, CEC, Cambridge and Canal, pursuant to approval and authorization duly given by resolutions adopted by their respective Boards of Directors, have each caused this

IN WITNESS WHEREOF, Boston Edison, Commonwealth Electric Company, Cambridge Electric Company and Canal Electric Company, pursuant to approval and authorization duly given by resolutions adopted by their respective Boards of Directors, have each caused these Articles of Merger to be executed by its president or one of its vice presidents and its secretary or one of its assistant secretaries.

Dated: April 10, 2006

BOSTON EDISON COMPANY

By: Douglas S. Horan
Name: Douglas S. Horan
Title: Senior Vice President/Strategy, Law & Policy and General Counsel

By: James J. Judge
Name: James J. Judge
Title: Senior Vice President, Treasurer & Chief Financial Officer

COMMONWEALTH ELECTRIC COMPANY

By: Douglas S. Horan
Name: Douglas S. Horan
Title: Senior Vice President/Strategy, Law & Policy and General Counsel

By: James J. Judge
Name: James J. Judge
Title: Senior Vice President, Treasurer & Chief Financial Officer

CAMBRIDGE ELECTRIC LIGHT COMPANY

By: Douglas S. Horan
Name: Douglas S. Horan
Title: Senior Vice President/Strategy, Law & Policy and General Counsel

By: James J. Judge
Name: James J. Judge
Title: Senior Vice President, Treasurer & Chief Financial Officer

CANAL ELECTRIC COMPANY

By: ______________________
Name: Douglas S. Horan
Title: Senior Vice President/Strategy, Law
& Policy and General Counsel

By: ______________________
Name: James J. Judge
Title: Senior Vice President, Treasurer & Chief Financial Officer

ANNEX I
to
Agreement and Plan of Merger

ARTICLES OF MERGER
of

BOSTON EDISON COMPANY
(A Massachusetts Utility Corporation)

and

COMMONWEALTH ELECTRIC COMPANY
(A Massachusetts Utility Corporation)
and

CAMBRIDGE ELECTRIC LIGHT COMPANY
(A Massachusetts Utility Corporation)

and

CANAL ELECTRIC COMPANY
(A Massachusetts Utility Corporation)

Pursuant to the provisions of Section 102A of Chapter 164 of the Massachusetts General Laws, the undersigned corporations adopt the following Articles of Merger for the purpose of merging Commonwealth Electric Company, Cambridge Electric Light Company and Canal Electric Company with and into Boston Edison Company, which shall be the Surviving Corporation:

1. Attached hereto and incorporated herein by reference is the Agreement and Plan of Merger dated as of April , 2006, of the undersigned corporations. The Surviving Corporation will furnish a copy of said agreement to any of its stockholders, or to any person who was a stockholder of a Constituent Corporation, upon written request and without charge. The Effective Time as defined therein is 12:01 A.M., Boston time on January 27, 2007.

2. The undersigned president or vice president and secretary or assistant secretary of each undersigned corporation hereby state under the penalties of perjury that the attached Agreement and Plan of Merger has been duly executed on behalf of such corporation and has been approved by the stockholders of such corporation and by the Department of Telecommunications and Energy of The Commonwealth of Massachusetts in the manner required by Section 96 of Chapter 164 of the Massachusetts General Laws.

3. The post office address of the initial principal office of the Surviving Corporation is 800 Boylston St.,, MA 02199.

4. The name, residence and post office address of each of the initial directors and the chairman, president, treasurer and secretary of the Surviving Corporation are as follows:

Name	Title	Residence	Post Office Address
Thomas J. May	Chairman of the Board, President and Chief Executive Officer	22 Longmeadow Drive Westwood, MA 02090	c/o 800 Boylston Street Boston, MA 02199
James J. Judge	Director, Senior Vice President, Treasurer and Chief Financial Officer	30 Cushing Hill Road Hanover, MA 02339	c/o 800 Boylston Street Boston, MA 02199
Douglas S. Horan	Director, Senior Vice President/Strategy, Law & Policy and General Counsel	171 Asbury St. Hamilton, MA. 01982	c/o 800 Boylston Street Boston, MA 02199
Richard J. Morrison	Secretary	60 Washburn Ave. Wellesley, MA. 02481	c/o 800 Boylston St. Boston, MA. 02199

5. The fiscal year of the Surviving Corporation initially adopted shall end on the last day of the month of December in each year.

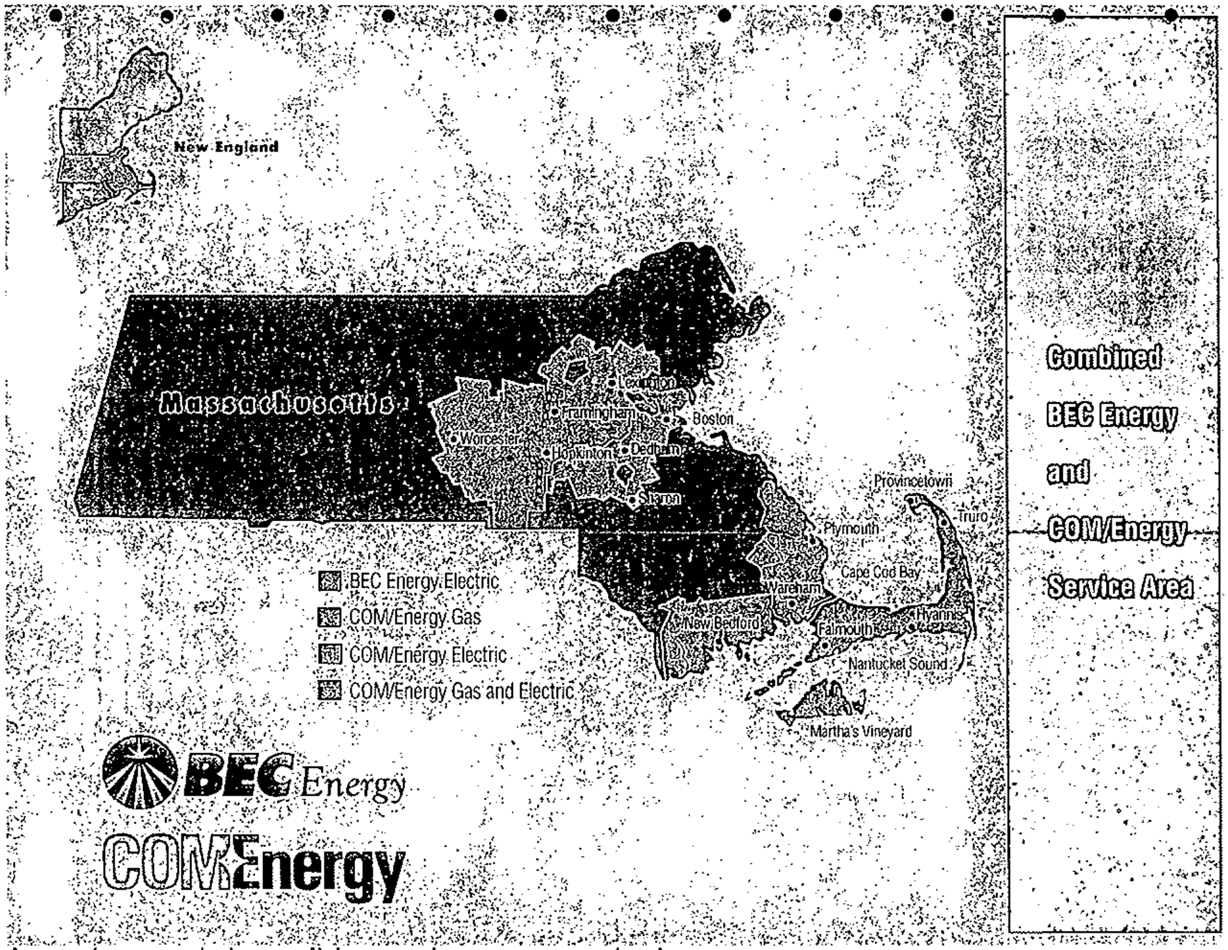
6. The date and time initially fixed in the Bylaws for the annual meeting of the stockholders of the Surviving Corporation is 11:00 a.m. on the last Tuesday in April of each year.

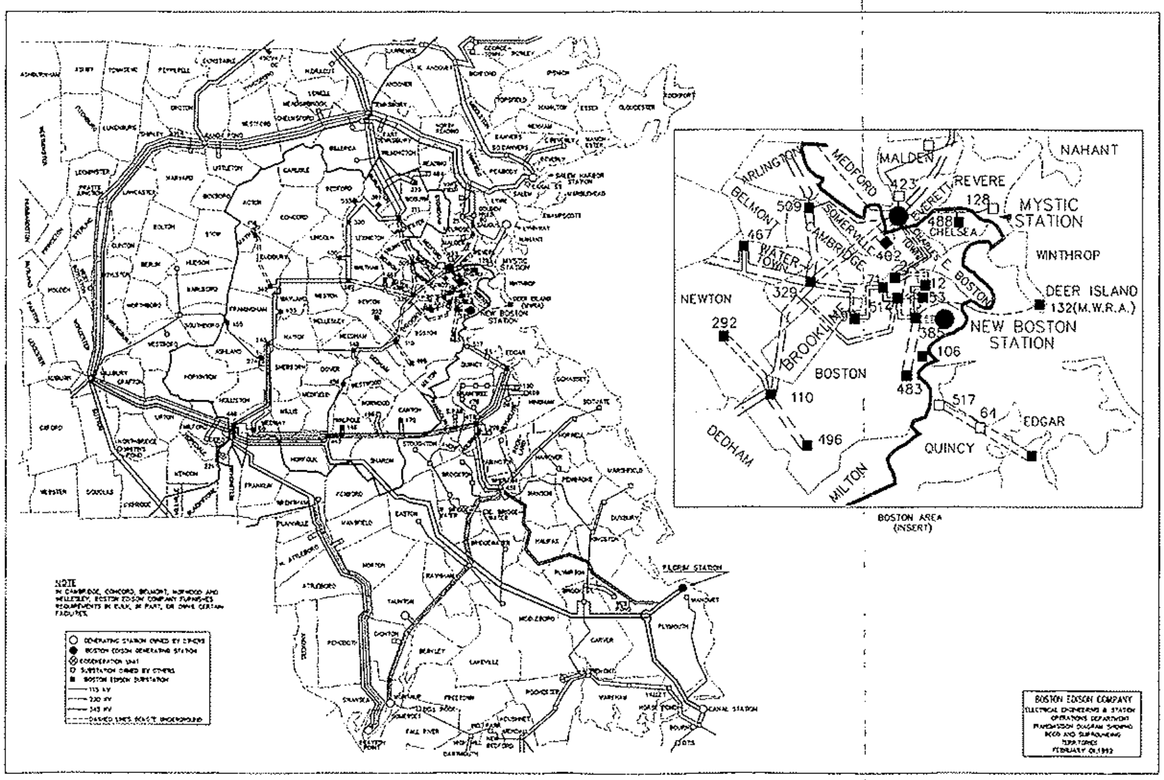
[Remainder of this page intentionally left blank.]

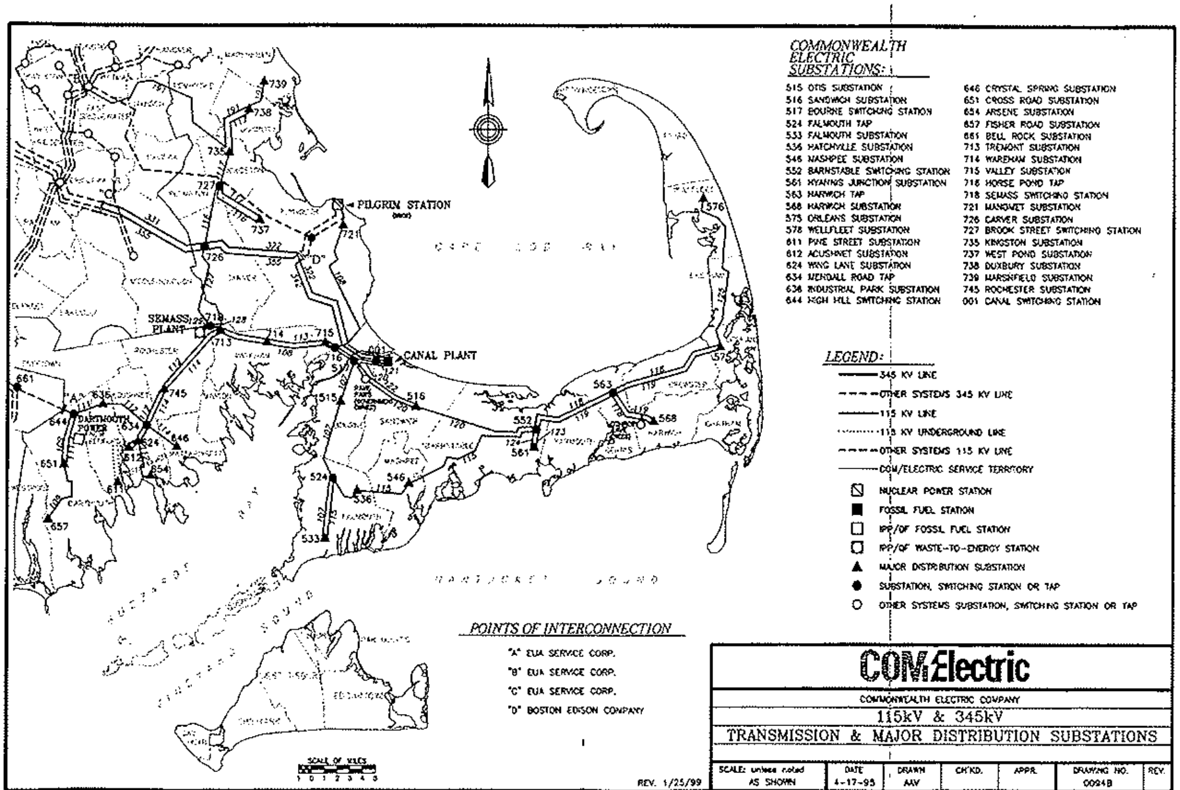
EXHIBIT K

Pages 2 to 3 contain maps which show the area of the Applicants' operations. Pages 4 to 6 show the Applicants' physical public utility properties, and that of its affiliate, NSTAR Gas Company.


New England
Massachusetts
Lexington
Framingham
Boston
Hopkinton
Dedham
Sharon
Electric Service Area
BEC Energy
BEC Energy
Service Area


New England
Massachusetts
Lexington
Framingham
Boston
Worcester
Hopkinton
Dedham
Plymouth
Provincetown
Truro
Cape Cod Bay
Wareham
New Bedford
Falmouth
Hyannis
Nantucket Sound
Martha's Vineyard
BEC Energy Electric
COM/Energy Gas
COM/Energy Electric
COM/Energy Gas and Electric
BEC Energy
COM/Energy
Combined
BEC Energy
and
COM/Energy
Service Area


NAHANT
MALDEN
MEDFORD
ARLINGTON
423
REVERE
128
MYSTIC
STATION
BELMONT
509
EVERETT
488
CHELSEA
467
SOMERVILLE
CAMBRIDGE
402
WINTHROP
WATER-
TOWN
E. BOSTON
NEWTON
329
12
53
DEER ISLAND
132(M.W.R.A.)
292
NEW BOSTON
STATION
BROOKLINE
106
BOSTON
483
110
517
64
EDGAR
DEDHAM
496
QUINCY
MILTON
BOSTON AREA
(INSERT)
PILGRIM STATION
CANAL STATION
NEW BOSTON STATION
BOSTON EDISON COMPANY


COMMONWEALTH ELECTRIC SUBSTATIONS:
515 OTIS SUBSTATION
516 SANDWICH SUBSTATION
517 BOURNE SWITCHING STATION
524 FALMOUTH TAP
533 FALMOUTH SUBSTATION
536 HATCHVILLE SUBSTATION
546 NASHPEE SUBSTATION
552 BARNSTABLE SWITCHING STATION
561 HYANNIS JUNCTION SUBSTATION
563 HARWICH TAP
568 HARWICH SUBSTATION
575 ORLEANS SUBSTATION
578 WELLFLEET SUBSTATION
611 PINE STREET SUBSTATION
612 ACUSHNET SUBSTATION
624 WING LANE SUBSTATION
634 MENDALL ROAD TAP
636 INDUSTRIAL PARK SUBSTATION
644 HIGH HILL SWITCHING STATION
646 CRYSTAL SPRING SUBSTATION
651 CROSS ROAD SUBSTATION
654 ARSENE SUBSTATION
657 FISHER ROAD SUBSTATION
661 BELL ROCK SUBSTATION
713 TREMONT SUBSTATION
714 WAREHAM SUBSTATION
715 VALLEY SUBSTATION
716 HORSE POND TAP
718 SEMASS SWITCHING STATION
721 MANOMET SUBSTATION
726 CARVER SUBSTATION
727 BROOK STREET SWITCHING STATION
735 KINGSTON SUBSTATION
737 WEST POND SUBSTATION
738 DUXBURY SUBSTATION
739 MARSHFIELD SUBSTATION
745 ROCHESTER SUBSTATION
001 CANAL SWITCHING STATION
LEGEND:
345 KV LINE
OTHER SYSTEMS 345 KV LINE
115 KV LINE
115 KV UNDERGROUND LINE
OTHER SYSTEMS 115 KV LINE
COM/ELECTRIC SERVICE TERRITORY
NUCLEAR POWER STATION
FOSSIL FUEL STATION
IPP/QF FOSSIL FUEL STATION
IPP/QF WASTE-TO-ENERGY STATION
MAJOR DISTRIBUTION SUBSTATION
SUBSTATION, SWITCHING STATION OR TAP
OTHER SYSTEMS SUBSTATION, SWITCHING STATION OR TAP
PILGRIM STATION
CANAL PLANT
SEMASS PLANT
DARTMOUTH POWER
POINTS OF INTERCONNECTION
"A" EUA SERVICE CORP.
"B" EUA SERVICE CORP.
"C" EUA SERVICE CORP.
"D" BOSTON EDISON COMPANY
SCALE OF MILES
REV. 1/25/99
COM/Electric
COMMONWEALTH ELECTRIC COMPANY
115kV & 345kV
TRANSMISSION & MAJOR DISTRIBUTION SUBSTATIONS
SCALE: unless noted AS SHOWN
DATE 4-17-95
DRAWN AAV
CH'KD.
APPR.
DRAWING NO. 0024B
REV.

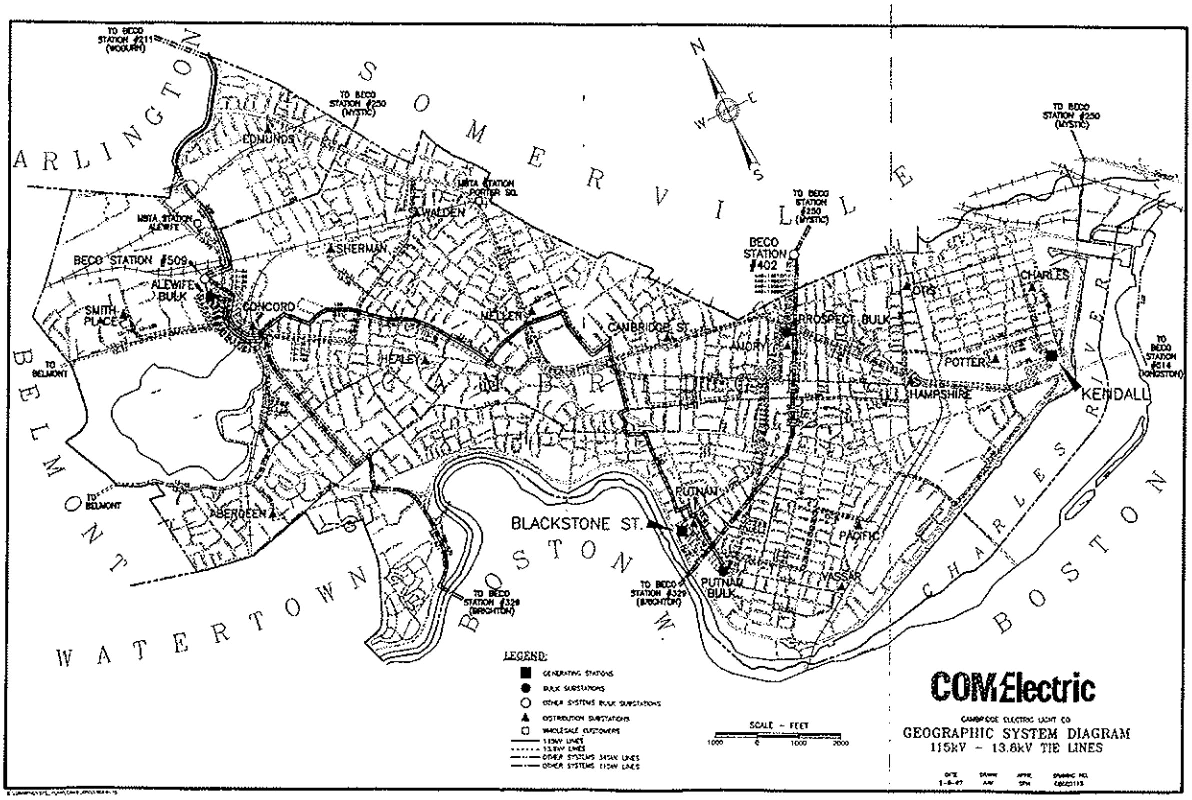

ARLINGTON
SOMERVILLE
BELMONT
WATERTOWN
BOSTON
CHARLES RIVER
BECO STATION #509
ALEWIFE BULK
CONCORD
SMITH PLACE
EDMUNDS
SHERMAN
WALDEN
MULLEN
CAMBRIDGE ST.
BECO STATION #402
PROSPECT BULK
OTIS
CHARLES
POTTER
HAMPSHIRE
KENDALL
HEALEY
AVERY
ABERDEEN
BLACKSTONE ST.
PUTNAM
PUTNAM BULK
PACIFIC
VASSAR
LEGEND:
COM/Electric
CAMBRIDGE ELECTRIC LIGHT CO
GEOGRAPHIC SYSTEM DIAGRAM
115kV ~ 13.8kV TIE LINES

EXHIBIT L

POST-FILING REGULATORY ORDERS

Any regulatory orders issued by state or federal agencies after this filing is made will be submitted to the Commission as Exhibit L to the Application.

EXHIBIT M

CROSS SUBSIDIZATION VERIFICATION

The proposed Transaction will not result in cross-subsidization or the pledge or encumbrance of utility assets. BECo is acquiring only regulated transmission and distribution assets and assets related to those functions at book value and is not acquiring assets owned prior to the Transaction by any non-regulated company, or any non-utility associate company as defined by Section 33.1(b)(2) of the Commission's regulations. In Order No. 669, the Commission identified certain verifications that applicants could make that would satisfy the Commission's concerns regarding any possible cross-subsidization, pledge, or encumbrance of utility assets associated with the proposed transaction. Order No. 669, at P 169. Consequently, consistent with the requirements of Order No. 669, BECo, through James J. Judge, Senior Vice President, Treasurer and Chief Financial Officer, verifies the Transaction will not result in, at the time of the transaction or in the future: (1) transfers of facilities between a traditional utility associate company with wholesale or retail customers served under cost-based regulation and an associate company; (2) new issuances of securities by traditional utility associate companies with wholesale or retail customers served under cost-based regulation for the benefit of an associate company; (3) new pledges or encumbrances of assets of a traditional utility associate company with wholesale or retail customers served under cost-based regulation for the benefit of an associate company; (4) new affiliate contracts between non-utility associate companies and traditional utility associate companies with wholesale or retail customers served under cost-based regulation, other than non-power goods and services agreements subject to review under Sections 205 and 206 of the FPA. Accordingly, BECo submits that there is no need for a detailed examination of cross-subsidization and encumbrance concerns in connection with the Transaction.

I, James J. Judge, being duly sworn, depose and say that the information contained in this Exhibit M is true and correct to the best of my knowledge, information and belief.

James J. Judge

James J. Judge

SUBSCRIBED AND SWORN to before me this 24th day of May 2006

Mary E. Grover

Notary Public, County of Suffolk
My Commission expires: 11/30/08

ATTACHMENT 1

Cambridge, Commonwealth and Canal

Jurisdictional Contracts

Contracts Review

Transmission and Distribution Contracts

Contract Name	FERC Rate Sched. Nos.	Parties	Date	Subject	Assignment	Consent
Canal Electric Company						
"Canal-Pilgrim Transmission"		BECo, Montaup, NEP	03/29/68	345kv line support	No provision	None required
"Equalization of Costs"		Montaup	12/01/65	Cost allocation	No provision	None required
Amende/Restated - Use of Quebec Interconnection		Numerous	12/01/81	Hydro-Quebec	Yes	None required for merger with Nepool member utility; Written notice to all parties prior to transfer
Preliminary Quebec Interconnection Support - Phase II		Numerous	06/01/84	Hydro-Quebec	Yes	None required for merger with Nepool member utility
Preliminary Quebec Interconnection Support - Phase II		Numerous	09/01/84	Hydro-Quebec	Yes	None required for merger with Nepool member utility
Commonwealth Electric Company						
Non-Firm Point to Point Tx Service		New England Power	12/30/96	Tariffed Service	No provision	None required
Related Facilities Agreement		Entergy Nuclear Generating	08/11/03	System upgrades	Yes	No consent for transfer to affiliate, successor or acquiror; assumption to be signed
Interconnection Agreement		Nantucket Electric Company	06/03/96	Tie in to Line 118	Yes	No consent required for transfer to affiliate
Amendment to Interconnection Agreement		Nantucked Electric Company	07/31/97	Cable intertie to grid	No provision	None required
Agreement for Emergency Backup Service		Entergy Nuclear Generating	11/15/01	Back-up service	Yes	No consent required for transfer by merger
Facilities Support Agreement		Entergy Nuclear Generating	No date	Facilities support	Yes	No consent required for transfer by merger
Distribution Service Agreement		MBTA - Not signed by either party	05/01/99	Distribution service	No provision	None required
Distribution Service Agreement (Diesels)		Southern Energy New England (Mirant)	05/15/98	Distribution service	No provision	None required
Interconnection and Site Agreement (WT Die: sels)		Southern Energy New England (Mirant)	05/15/98	Interconnection	Yes	No consent required for assignment to affiliate
Interconnection and Site Agreement (OB Diesels)		Southern Energy New England (Mirant)	05/15/98	Interconnection	Yes	No consent required for assignment to affiliate
Cambridge Electric Light Company						
Interconnection Agreement		Mirant Kendall LLC	10/09/01	Interconnection	Yes	No consent required for assignment to affiliate
Firm Transmission Service Agreement		MBTA - Alewife Station	09/13/93	Transmission	No provision; tariffed service	

Attachment 2

NSTAR Electric Proposed Merger Entry
Adjustments Debit/(Credit)
Balances as of 12/31/05 per FERC Form 1

Account Number	Description	Commonwealth Electric Company	Cambridge Electric Light Co	Canal Electric Company	Boston Edison Co.
101	Electric Plant in Service	(777,544,713)	(188,505,559)	(7,007,739)	973,358,041
105	Electric Plant Held for Future Use	(489,285)	-		489,285
106	Completed Construction not Classified	(19,215,962)	(9,490,118)		28,706,080
107	CWIP	(8,464,584)	(6,499,678)		14,964,262
108	Accumulated Provision for Depreciation of Utility Plant	281,257,854	57,169,277		(338,427,131)
111	Accumulated Provision for Amortization of Electric Utility Plant	6,528,938	1,139,569		(7,668,507)
121	Nonutility Property	(41,054)	(119,226)	(8,994)	169,278
122	Accumulated Provision for Depreciation & Amortization	-	18,835		(18,835)
123.1	Investment in Subsidiary Companies	(2,073,456)	(3,300,181)	(1,290,841)	6,664,478
124	Other Investments	(14,400)	(5,000)		19,400
131	Cash	(2,173,454)	(477,621)	(20,920)	2,671,995
142	Customer Accounts Receivable	(43,586,225)	(14,748,444)		58,334,669
143	Other Accounts Receivable	(1,225,125)	(283,531)	(18,517)	1,527,173
144	Accumulated Provision for Uncollectible Accounts	3,705,113	691,565		(4,396,701)
146	Accounts Receivable from Associated Companies	(32,361,125)	(11,922,417)	(62,500,137)	106,783,679
154	Plant Materials and Operating Supplies	(7,463,249)	(2,882,795)		10,346,044
165	Prepayments	(31,022,160)	(1,086,544)	(7,427)	32,116,431
171	Interest and Dividends Receivable	(819)	-	(356,777)	357,596
172	Rents Receivable	-	(1,462)		1,462
173	Accrued Utility Revenues	(13,425,657)	(1,233,525)		14,659,182
181	Unamortized Debt Expenses	(128,985)	(21,649)		150,634
182.3	Other Regulatory Assets	(565,492,549)	(93,191,149)		658,683,698
185	Temporary Facilities	4,545	91,027		(95,575)
186	Misc. Deferred Debits	(142,874,866)	(32,888,875)		175,763,741
190	Accumulated Deferred Income Taxes	(18,703,105)	(7,530,939)	(1,111,472)	27,345,516
	TOTAL ASSETS	(1,375,126,320)	(315,056,749)	(72,322,824)	1,762,505,893
201	Common Stock Issued	51,099,300	8,865,000	8,863,325	(68,827,625)
207	Premium on Capital Stock	212,309,647	54,132,072	44,712,531	(311,154,250)
214	Capital Stock Expense	-	-	(12,019)	12,019
216	Unappropriated Retained Earnings	92,177,451	25,869,752	9,317,113	(127,364,316)
216.1	Unappropriated Undistributed Subsidiary Earnings	9,281	1,096,431		(1,105,712)
224	Other Long-Term Debt	80,225,573	25,000,000		(105,225,573)
227	Obligations Under Capital Leases - Noncurrent	-	-	6,491,089	(6,491,089)
229	Accumulated Provision for Rate Refunds	6,828,339	3,300,364		(10,128,703)
230	Asset Retirement Obligation	318,935	-	-	(318,935)
231	Notes Payable	-	35,900,000		(35,900,000)
232	Accounts Payable	26,417,772	12,967,564		(39,385,336)
233	Notes Payable to Associated Companies	332,542,905	-		(332,542,905)
234	Accounts Payable to Associated Companies	53,657,538	16,107,816	190,738	(69,956,092)
235	Customer Deposits	1,143,159	670,926		(1,814,085)
236	Taxes Accrued	101,073	-	1,072,888	(1,173,961)
237	Interest Accrued	1,577,916	492,235		(2,070,151)
241	Tax Collections Payable	323,083	210,451		(533,534)
242	Misc. Current & Accrued Liabilities	38,759,288	19,478,225	108,530	(58,346,043)
243	Obligations Under Capital Leases - Current	-	-	516,650	(516,650)
252	Customer Advances for Construction	2,455,710	435,622		(2,891,332)
253	Other Deferred Credits	232,828,123	58,092,321	-	(290,920,444)
254	Other Regulatory Liabilities	734,862	4,618,358		(5,353,220)
255	Accumulated Deferred Investment Tax Credits	3,409,399	866,597		(4,276,028)
282	Accumulated Deferred Income Taxes-Other Property	85,363,006	25,978,487		(111,341,493)
283	Accumulated Deferred Income Taxes-Other	152,843,960	21,174,438	1,061,979	(175,080,377)
	TOTAL LIABILITIES	1,375,126,320	315,056,749	72,322,824	(1,762,505,893)

References 2005 FERC Form 1 pages 110-113, 200-201

VERIFICATION

Commonwealth of Massachusetts)
) ss:
County of Suffolk)

I, James J. Judge, being duly sworn, depose and say that the information for the Section 203 Application in this proceeding is true and correct to the best of my knowledge, information and belief.

James J. Judge
James J. Judge

SUBSCRIBED AND SWORN to before me this 24th day of May 2006

Mary E. Grover
Notary Public, County of Suffolk
My Commission expires: 11/30/08

VERIFICATION

Commonwealth of Massachusetts)
) ss:
County of Suffolk)

I, James J. Judge, being duly sworn, depose and say that the information for the Section 204 Application in this proceeding is true and correct to the best of my knowledge, information and belief.

James J. Judge
James J. Judge

SUBSCRIBED AND SWORN to before me
this 24th day of May 2006

Mary E. Groner
Notary Public, County of Suffolk
My Commission expires: 11/30/08

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

BOSTON EDISON COMPANY **CAMBRIDGE ELECTRIC LIGHT COMPANY** **COMMONWEALTH ELECTRIC COMPANY** **CANAL ELECTRIC COMPANY**	**DOCKET NO. EC06-___-000**

NOTICE OF FILING

Take notice that, on May 26, 2006, Boston Edison Company ("BECo"), Cambridge Electric Light Company ("Cambridge"), Commonwealth Electric Company ("Commonwealth") and Canal Electric Company ("Canal") (collectively, "the Applicants"), each doing business chiefly in Eastern Massachusetts, each a subsidiary of NSTAR and each a public utility as defined in Section 201(e) of the Federal Power Act, submitted an application in the above-captioned proceedings under Section 203 of the Federal Power Act for a merger under which the facilities, properties and other rights, assets, franchises and liabilities of Cambridge, Commonwealth and Canal will vest in BECo, and Cambridge, Commonwealth and Canal will then cease to exist.

Copies of the filing were served upon the Governor and the Attorney General of the Commonwealth of Massachusetts, the Massachusetts Department of Telecommunications and Energy, ISO New England, Inc., the Massachusetts Port Authority which is the Applicants' sole wholesale requirements customer, and the Applicants' local wholesale transmission, distribution and interconnection customers.

Any person desiring to intervene or to protest this filing must file in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211 and 385.214). Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a notice of intervention or motion to intervene, as appropriate. Such notices, motions, or protests must be filed on or before the comment date. Anyone filing a motion to intervene or protest must serve a copy of that document on the Applicant. On or before the comment date, it is not necessary to serve motions to intervene or protests on persons other than the Applicant.

The Commission encourages electronic submission of protests and interventions in lieu of paper using the "eFiling" link at http://www.ferc.gov. Persons unable to file electronically should submit an original and 14 copies of the protest or intervention to the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426.

This filing is accessible on-line at http://www.ferc.gov, using the "eLibrary" link and is available for review in the Commission's Public Reference Room in Washington, D.C. There is an "eSubscription" link on the web site that enables subscribers to receive email notification when a document is added to a subscribed docket(s). For assistance with any FERC Online service, please email FERCOnlineSupport@ferc.gov, or call (866) 208-3676 (toll free). For TTY, call (202) 502-8659.

Comment Date: 5:00 pm Eastern Time on __________.

Magalie R. Salas
Secretary

LIST OF RECIPIENTS

ANP Blackstone Energy Co.
204 Elm Street
Blackstone, MA 01504

Concord Municipal Light Plant
Attn: Daniel Sack
1175 Elm Street
P.O. Box 1029
Concord, MA 01742

Wellesley Municipal Light Plant
Attn: Richard Joyce
455 Worcester Street
Wellesley, MA 02181

Belmont Municipal Light Plant
Attn: General Manager
P.O. Box 168
40 Prince Street
Belmont, MA 02478

Massachusetts Bay Transportation Authority
Attn: Mr. Ray O'Brien
10 Park Plaza
7th Floor
Boston, MA 02116-3933

Mass Port Authority
Attn: Mr. Stan Phillips
1 Harbor Side Drive
Suite 200
East Boston, MA 02128

New England Power – Nantucket Cable
Attn: Vice President Power Supply
25 Research Drive
Westboro, MA 01582-0010

Northeast Energy Associates
Attn: James Willitts
P.O. Box 1213
Bellingham, MA 02019

Entergy Nuclear Generation, Inc.
Attn: Brian Collins
600 Rocky Hill Road
Plymouth, MA 02360

Mirant Kendall, LLC
Attn: Accounts Payable
1155 Perimeter Center West
Atlanta, GA 30338

Mirant Americas Energy Marketing
Attn: Accounts Payable
1155 Perimeter Center West
Atlanta, GA 30338

NEMA and SEMA Real Time Locational Marginal Pricing (LMP)
Years 2004 and 2005
Monthly Load Weighted Data

	NEMA 2004	SEMA 2004	Difference 2004	Percentage Difference	NEMA 2005	SEMA 2005	Difference 2005	Percentage Difference
Real Time								
January	76.43	75.89	0.54	0.7%	67.91	67.04	0.87	1.3%
February	48.96	48.65	0.31	0.6%	54.03	53.43	0.6	1.1%
March	47.1	46.55	0.55	1.2%	64.32	64.16	0.16	0.2%
April	50.56	50.06	0.5	1.0%	62.57	60.69	1.88	3.0%
May	55.07	53.69	1.38	2.5%	60.07	57.35	2.72	4.5%
June	51.79	51.07	0.72	1.4%	69.49	64.6	4.89	7.0%
July	49.85	48.98	0.87	1.7%	79.09	72.77	6.32	8.0%
August	50.01	48.38	1.63	3.3%	102.81	90.34	12.47	12.1%
September	44.75	44.52	0.23	0.5%	106.85	102.04	4.81	4.5%
October	53.16	51.09	2.07	3.9%	115.04	112.43	2.61	2.3%
November	51.14	50.88	0.26	0.5%	75.44	75.36	0.08	0.1%
December	59.99	59.31	0.68	1.1%	100.48	100.37	0.11	0.1%
Average				1.5%				3.7%

NSTAR Electric
Comparison of 2005 Retail Transmission Rate
$ in Millions

Line	Description	Consolidated	BECo	Commonwealth *	Cambridge *
	Regional Transmission Costs				
1	Retail RNS Cost	$ 89.621	$ 67.131	$ 15.586	$ 6.904
2	Regional Anciliary Services				
3	Retail Schedule & Dispatch Cost	6.799	4.916	1.380	0.503
4	Retail Congestion Management Cost **	-	-	-	-
5	System Restoration & Planning Cost	1.487	1.051	0.317	0.119
6	Load Dispatching (REMVEC)	0.383	0.284	0.099	-
7	NEPOOL Administration (Transmission)	0.075	0.075	-	-
8	VAR Support Cost	-	-	-	-
9	Total Estimated Regional Transmission Costs	$ 98.365	$ 73.457	$ 17.382	$ 7.526
10	**Local Transmission Costs**				
11	Local Network Service (LNS) Costs				
12	LNS and Scheduling & Dispatch Revenue Req.	$ 107.468	86.129	$ 17.827	$ 22.283
13	13.8kv facilities transferred to Distribution Rates	-	-	-	(13.421)
14	RNS Revenues Received from NEPOOL ***	(79.882)	(66.229)	(9.947)	(3.706)
15	Dispatch Center Revenue Requirement	4.273	4.109	-	-
16	Schedule 1 Revenues Received	(4.375)	(4.375)	(0.142)	-
17	Estimated LNS Revenue Requirement	$ 27.484	$ 19.634	$ 7.737	$ 5.156
18	**Total Estimated Transmission Costs**	$ 125.849	$ 93.091	$ 25.119	$ 12.682
19	2005 Billed GWH	21,568.168	15,487.787	4,363.964	1,716.417
20	2005 Retail Transmission Rate	$ 0.00583	$ 0.00601	$ 0.00576	$ 0.00739
21	Difference in $/kwh from Consolidated	$ -	$ (0.000176)	$ 0.000079	$ (0.001554)
22	Revenue impact ($ in millions)	$ (5.043)	$ (2.721)	$ 0.344	$ (2.667)
23	Percentage increase (decrease)		-2.92%	1.37%	-21.03%

* The LNS formula rate for Cambridge and Commonwealth are currently the subject of FERC settlement procedures in Docket ER05-742. The calculations presented in this exhibit are based on the formula tariff as currently under discussion.

** This analysis excludes congestion costs as the amount and future location of these costs are too highly uncertain to be used as going forward proxies.

*** Excludes FERC incentives for being part of an RTO and for new transmission investment

ATTACHMENT D

ANNUAL TRANSMISSION REVENUE REQUIREMENTS

The Transmission Revenue Requirements for Cambridge ("the Company") will reflect the costs for its Transmission System, including costs attributable to those incurred by the Company in owning, leasing, maintaining and supporting the Transmission System net of revenues for transmission services provided under any other FERC accepted tariff or under any contract with other parties that provides reimbursement to the Company for transmission related services. Under no circumstances shall the Company's Local Network Service rates include costs that are charged through any other rate or tariff. The Transmission Revenue Requirements will be an annual calculation based on the estimated costs for its Transmission System during the Service Year.

The Company shall make an annual informational filing with the FERC on or before May 31 of each year which shall include a True-up of estimated costs and revenues, and actual costs and revenues for the preceding Service Year. Actual costs will be determined using data required to be reported annually in the FERC Form 1 and recorded on the Company's books in accordance with FERC's Uniform System of Accounts; unless the use of other data, such as subaccount balances, is specifically required by the provisions below, in which case an independent certified public accountant, the "auditor" as defined in Section 4, shall certify that the development, accuracy and application of such other data is in accordance with the provisions of this Local Service Schedule. Such certification will be included with the annual informational filing along with adequate detail that supports the values contained within the True-up calculation.

References to specific FERC Form1 pages, line numbers and columns included in this Local Service Schedule are based on the Company's 2004 Form 1. Subsequent FERC changes to Form 1 may be adopted to the extent they are consistent with the provisions and terms of this Local Service Schedule and not otherwise prohibited by FERC.

I. DEFINITIONS

Capitalized terms not otherwise defined in Section II.1 of the OATT or the Local Service Schedule and as used herein have the following definitions:

A. ALLOCATION FACTORS

1. Transmission Wages and Salaries Allocation Factor shall equal the ratio of transmission-related direct wages and salaries including those of affiliated companies as reported in the Company's annual FERC Form 1, page 354, line 19, column (b) to the Company's total direct wages and salaries including those of the affiliated companies as reported in the Company's FERC Form 1, page 354, line 25, column (b), and excluding administrative and general wages and salaries as reported in the Company's FERC Form 1, page 354, line 24, column (b). All allocations and assignments of FERC Account balances shall be certified in accordance with the second paragraph of this Attachment D.

2. Plant Allocation Factor shall equal the ratio of the sum of Transmission Plant, excluding HQ leases, plus Transmission Related Intangible and General Plant to Total Plant in Service excluding HQ Leases. All allocations and assignments of FERC Account balances shall be certified in accordance with the second paragraph of this Attachment D.

B. TERMS

Administrative and General Expense shall equal the expenses as reported in the Company's FERC Form 1, page 323, line 168, column (b), excluding the cost of the Auditor for services provided under the terms of the second paragraph of this Attachment D, Property Insurance included in FERC Account No. 924, Regulatory Commission Expense included in FERC Account 928, and Advertising Expense included in FERC Account No. 930.1.

Amortization of Gain on Reacquired Debt shall equal the amortization amount recorded in FERC Account 429.1.

Amortization of Loss on Reacquired Debt shall equal the expenses as recorded in FERC Account No. 428.1.

Amortization of Investment Tax Credits shall equal the credits as recorded in FERC Account No. 411.4.

Depreciation Expense for Transmission Plant shall equal the transmission expenses as recorded in FERC Account No. 403 as reported in the Company's annual FERC Form 1 page 336, line 7, column (b).

General Plant shall equal the gross plant balance as recorded in FERC Account Nos. 389-399.

General Plant Depreciation Expense shall equal the general plant expenses as recorded in FERC Account No. 403 and reported in the Company's annual FERC Form 1, page 336, line 9, column (b).

General Plant Depreciation Reserve shall equal the general reserve balance as recorded in FERC Account No. 108 and reported in the Company's annual FERC Form 1, page 219, line 27, column (b).

Hydro-Quebec DC Facilities (HQ Leases) shall equal the balance in capital leases as recorded in FERC Account Nos. 350-359 and FERC Account Nos. 389-399. All assigned or allocated balances shall be certified in accordance with the second paragraph of this Attachment D.

Intangible Plant shall equal the gross plant balance as recorded in FERC Account No. 303 as reported in the Company's annual FERC Form 1, page 205, line 4, column (g). The only allowable Intangible Plant for inclusion in the Local

Service Schedule are software, patent or rights costs. All assigned or allocated balances shall be certified in accordance with the second paragraph of this Attachment D.

Intangible Plant Amortization Expense shall equal amortization expenses as recorded in FERC Account Nos. 404-405 as reported in the Company's annual FERC Form 1, page 336, line 1, column (f). The only allowable Intangible Plant Amortization Expense for inclusion in the Local Service Schedule is the amortization of software, patent or rights costs. All assigned or allocated balances shall be certified in accordance with the second paragraph of this Attachment D.

Intangible Plant Amortization Reserve shall equal the amortization reserve balance as recorded in FERC Account No. 111. The only allowable Intangible Plant Amortization Reserve for inclusion in the Local Service Schedule is that related to the amortization of software, patent or rights costs. All assigned or allocated balances shall be certified in accordance with the second paragraph of this Attachment D.

Other Regulatory Assets/Liabilities - FAS 106 shall equal the net of the FAS 106 balance as recorded in FERC Account No. 182.3 and any FAS 106 balance as recorded in the FERC Account No. 254. All assigned or allocated balances shall be certified in accordance with the second paragraph of this Attachment D. Other

Regulatory Assets/Liabilities - FAS 109 shall equal the net of the FAS 109 balance in FERC Account No. 182.3 and any FAS 109 balance as recorded in the FERC Account No. 254. All assigned or allocated balances shall be certified in accordance with the second paragraph of this Attachment D.

Payroll Taxes shall equal those payroll expenses as recorded in the FERC Account No. 408.1. All assigned or allocated balances shall be certified in accordance with the second paragraph of this Attachment D.

Plant Held for Future Use shall equal the balance in FERC Account No. 105.

Prepayments shall equal the prepayment balance as recorded in FERC Account No. 165.

Property Insurance shall equal the expenses as recorded in FERC Account No. 924.

Total Accumulated Deferred Income Taxes shall equal the net of the deferred tax balance as recorded in FERC Account Nos. 281-283 and 190 for those balances that are directly related to transmission, excluding those directly related to distribution or other businesses. All assigned or allocated balances shall be certified in accordance with the second paragraph of this Attachment D.

Total Gain on Reacquired Debt shall equal the gain as recorded in FERC Account No. 257.

Total Loss on Reacquired Debt shall equal the expenses as recorded in FERC Account No. 189.

Total Municipal Tax Expense shall equal the municipal tax expenses as recorded in FERC Account No. 408.1 as reported in the Company's annual FERC Form 1, page 263, line 5, column (i).

Total Plant in Service shall equal the total gross plant balance as recorded in FERC Account Nos. 301-399 excluding HQ Leases recorded in those accounts.

Total Transmission Depreciation Reserve shall equal the transmission reserve balance as recorded in FERC Account No. 108 as reported in the Company's annual FERC Form 1, page 219, line 25, column (c), excluding HQ-related amounts recorded in that account.

Transmission Operation and Maintenance Expense shall equal all transmission-related expenses as recorded in FERC Account Nos. 560-564 and 566-576.5, and shall exclude; (i) all HQ HVDC expenses recorded in those accounts, and (ii) expenses already included in Transmission Support Expense, as described in Section II.K, which are recorded in those accounts. All allocated or assigned balances shall be certified in accordance with the second paragraph of this Attachment D.

Transmission Plant shall equal the balance as recorded in FERC Account Nos. 350-359, adjusted to exclude the capital leases in the Hydro-Quebec DC Facilities (HQ Leases). All allocated or assigned balances shall be certified in accordance with the second paragraph of this Attachment D.

Transmission Plant Materials and Supplies shall equal the balance as assigned to transmission, as recorded in FERC Account No. 154 as reported in the Company's annual FERC Form 1, page 227, line 8, column (c). All allocated or assigned balances shall be certified in accordance with the second paragraph of this Attachment D.

II. CALCULATION OF TRANSMISSION REVENUE REQUIREMENTS

The Transmission Revenue Requirement shall equal the sum of (A) Return and Associated Income Taxes, (B) Transmission Depreciation and Amortization Expense, (C) Transmission Related Amortization of Gain/Loss on Reacquired Debt, (D) Transmission Related Amortization of Investment Tax Credits, (E) Transmission Related Municipal Tax Expense, (F) Transmission Related Payroll Tax Expense, (G) Transmission Operation and Maintenance Expense, (H) Transmission Related Administrative and General Expenses, (I) Transmission Related Integrated Facilities Charges, minus (J)

Transmission Support Revenue, plus (K) Transmission Support Expense, plus (L) Transmission-Related Expense from Generators, minus (M) Transmission Rents Received from Electric Property, minus (N) Short-Term and Non-Firm Point-To-Point Service Revenues, minus (O) Regional Network Services (RNS) Revenues, minus (P) Through or Out Revenues, minus (Q) ISO-NE Scheduling and Dispatch Revenues, plus (R) 13.8 kV Transmission Facilities Revenue Requirement.

A. Return and Associated Income Taxes shall equal the product of the Transmission Investment Base and the Cost of Capital Rate.

1. Transmission Investment Base

The Transmission Investment Base will be the year end balances of (a) Transmission Plant, plus (b) Transmission Related Intangible and General Plant, plus (c) Transmission Plant Held for Future Use, less (d) Transmission Related Depreciation and Amortization Reserve, less (e) Transmission Related Accumulated Deferred Taxes, plus (f) Transmission Related Gain/Loss on Reacquired Debt, plus (g) Other Regulatory Assets/Liabilities, plus (h) Transmission Prepayments, plus (i) Transmission Materials and Supplies, plus (j) Transmission Related Cash Working Capital.

(a) Transmission Plant will equal the balance of the investment in Transmission Plant. This value excludes the capital leases in the Hydro-Quebec DC Facilities (HQ Leases).

(b) Transmission Related Intangible and General Plant shall equal the sum of the balance of investment in Intangible Plant and General Plant multiplied by the Transmission Wages and Salaries Allocation Factor.

(c) Transmission Plant Held for Future Use shall equal the balance of Transmission-related Plant Held for Future Use (FERC Account No. 105) provided in conformance with the FERC Uniform System of Accounts, Instruction E, Account No. 105 which requires that "…property included in this account shall be classified according to detail accounts (301-399)…and shall be maintained in such detail as though the property were in service."

(d) Transmission Related Depreciation and Amortization Reserve shall equal the balance of Total Transmission Depreciation Reserve as reported in the Company's annual FERC Form 1, page 219 line 25, column (c), plus the balance of Transmission Related Intangible Plant Amortization Reserve and Transmission Related General

Plant Depreciation Reserve. Transmission Related Intangible Plant Amortization Reserve and Transmission Related General Plant Depreciation Reserve shall equal the product of (i) the sum of the Intangible Plant Amortization Reserve and General Plant Depreciation Reserve and (ii) the Transmission Wages and Salaries Allocation Factor. The Total Transmission Depreciation Reserve balance excludes any amounts related to the capital leases in the Hydro-Quebec DC Facilities (HQ Leases). All allocated or assigned balances shall be certified in accordance with the second paragraph of this Attachment D.

(e) Transmission Related Accumulated Deferred Taxes shall equal the electric balance of Total Accumulated Deferred Income Taxes (for those balances that are directly related to transmission, plus the balances not directly related to other businesses), with the remaining accumulated deferred taxes not directly related to other businesses being allocated on the same basis used for the related rate base assets. All allocated or assigned balances shall be certified in accordance with the second paragraph of this Attachment D.

(f) Transmission Related Gain/Loss on Reacquired Debt shall equal the electric balance of Total Gain/Loss on Reacquired Debt multiplied by the Plant Allocation Factor.

(g) Other Transmission Related Regulatory Assets/Liabilities shall equal the electric balance of any deferred rate recovery of FAS 106 expenses multiplied by the Transmission Wages and Salaries Allocation Factor, plus the electric balance of FAS 109 multiplied by the Plant Allocation Factor. All allocated or assigned balances shall be certified in accordance with the second paragraph of this Attachment D.

(h) Transmission Prepayments shall equal the electric balance of Prepayments multiplied by the Transmission Wages and Salaries Allocation Factor.

(i) Transmission Materials and Supplies shall equal the electric balance of Transmission Plant Materials and Supplies.

(j) Transmission Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of the Transmission Operation and Maintenance Expense included in Section II.G, Transmission

Related Administrative and General Expenses included in Section II.H, and Transmission Support Expenses included in Section II.K.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) the Weighted Cost of Capital, plus (b) Federal Income Tax plus (c) State Income Tax.

(a) The Weighted Cost of Capital will be calculated based upon the capital structure at the end of each year and will equal the sum of (i) and (ii) below.

(i) the long-term debt component, which equals the product of the actual weighted average embedded cost to maturity of the long-term debt then outstanding and the ratio that long-term debt is to the total capital.

(ii) the return on equity component shall be the product of the allowed ROE of the common equity and the ratio that common equity is to the total capital; provided that the common equity ratio as set forth in this Section shall be the Company's actual common equity ratio, but in no event shall the common equity ratio exceed 60 percent for 2005, 55 percent for 2006 and 50 percent for 2007 and beyond. The allowed ROE for all or any part of a Service Year shall be the ROE established pursuant to the provisions of the Federal Power Act for the Company under this Local Service Schedule, subject to refund as may be ordered by the Commission in the proceeding in which any ROE change is instituted.

(b) Federal Income Tax shall equal

$$\frac{(A+[(C+B)/D])(FT)}{1 - FT}$$

where FT is the Federal Income Tax Rate and A is the return on equity component, as determined in Section II.A.2.(a) (ii) above, B is Transmission Related Amortization of Investment Tax Credits, as determined in Section II.D below, C is the Equity AFUDC component of Transmission Depreciation and Amortization Expense, as defined in Section II.B below, and D is Transmission Investment Base, as determined in Section II.A.1 above.

(c) State Income Tax shall equal

$$\frac{(A+[(C+B)/D] + \text{Federal Income Tax})(ST)}{1 - ST}$$

where ST is the State Income Tax Rate, A is return on equity component determined in Section II.A.2.(a)(ii) above, B is the Amortization of Investment Tax Credits as determined in Section II.D below, C is the equity AFUDC component of Transmission Depreciation and Amortization Expense, as defined in Section II.B below, D is the Transmission Investment Base, as determined in II.A.1 above and Federal Income Tax is the rate determined in Section II.A.2.(b) above.

B. Transmission Depreciation and Amortization Expense shall equal the sum of (i) the Depreciation Expense for Transmission Plant and (ii) an allocation of Intangible Plant Amortization Expense and General Plant Depreciation Expense, which is calculated by multiplying the sum of (a) Intangible Plant Amortization Expense and (b) General Plant Depreciation Expenses by the Transmission Wages and Salaries Allocation Factor. All allocations and assignments shall be certified in accordance with the second paragraph of this Attachment D.

C. Transmission Related Amortization of Gain/Loss on Reacquired Debt shall equal the electric Amortization of Gain/Loss on Reacquired Debt multiplied by the Plant Allocation Factor.

D. Transmission Related Amortization of Investment Tax Credits shall equal the electric Amortization of Investment Tax Credits multiplied by the Plant Allocation Factor.

E. Transmission Related Municipal Tax Expense shall equal the total electric municipal tax expense reported in the Company's FERC Form 1, page 263, Local Real Estate and Personal Property Taxes, column (i), multiplied by the Plant Allocation Factor.

F. Transmission Related Payroll Tax Expense shall equal the total electric payroll tax expense reported in the Company's FERC Form 1, page 263, Service Company Allocations and Capitalization, column (i), multiplied by the Transmission Wages and Salaries Allocation Factor.

G. Transmission Operation and Maintenance Expense shall equal the Transmission Operation and Maintenance Expenses.

H. Transmission Related Administrative and General Expenses shall equal the sum of the (1) Administrative and General Expense multiplied by the Transmission Wages and Salaries Allocation Factor, (2) Property Insurance included in FERC Account No. 924, line 156 multiplied by the Transmission Plant Allocation Factor, and (3) expenses included in Account No. 928, line 160 related to (i) transmission related FERC Assessments, plus (ii) any other Federal and State transmission related expenses or assessments, plus (iii) the cost of the Auditor for services provided under the terms of the second paragraph of this Attachment D. All adjustments and assignments shall be certified in accordance with the second paragraph of this Attachment D.

I. Transmission Related Integrated Facilities Charges shall equal the transmission payments to affiliates for use of the integrated transmission facilities of those affiliates included in FERC Account No. 565. Such amount shall be certified in accordance with the second paragraph of this Attachment D.

J. Transmission Support Revenues shall equal the revenue received for transmission support included or includable in FERC Account Nos. 454 or 456 but excluding any revenue received for use of the Company's entitlement in the Hydro-Quebec Facilities. Such amount shall be certified in accordance with the second paragraph of this Attachment D.

K. Transmission Support Expense shall equal the expense paid by the Company for transmission support included in FERC Account No. 565, but excluding expenses for the Hydro-Quebec DC Facilities. Such amount shall be certified in accordance with the second paragraph of this Attachment D.

L. Transmission-Related Expense from Generators shall equal the expenses from generators that are reflected in a filing made by the Company with the

Commission under Section 205 of the Federal Power Act and accepted by the Commission for recovery under the Local Service Schedule and included or includable in FERC Account No. 565. Such amount shall be certified in accordance with the second paragraph of this Attachment D.

M. Transmission Rents Received from Electric Property shall equal any FERC Account No. 454 Rents from Electric Property, associated with Transmission Plant but not reflected as a credit in Transmission Support Revenues in Section II.K. Such amount shall be certified in accordance with the second paragraph of this Attachment D.

N. Short-Term and Non-Firm Point-to-Point Service Revenues shall equal the applicable wheeling revenues received for Local Point-To-Point Service provided under this Local Service Schedule, including the transmission component of the Company's Third-Party Sales, as recorded in FERC Account Nos. 447 and 456. Such amount shall be certified in accordance with the second paragraph of this Attachment D.

O. Regional Network Services (RNS) Revenues shall equal Commonwealth's RNS revenues pursuant to the Tariff, as included or includable in FERC Account Nos. 454 or 456 but excluding any incremental revenues associated with FERC-approved adders for RTO participation and new investment. Such amount shall be certified in accordance with the second paragraph of this Attachment D.

P. Through or Out Revenues shall equal the distribution of revenues received by the Company for Through or Out Service pursuant to the Tariff as included or includable in FERC Account Nos. 454 or 456. Such amount shall be certified in accordance with the second paragraph of this Attachment D.

Q. ISO-NE Scheduling and Dispatch Revenues shall be the amount of revenues received by the Company from ISO-NE for scheduling and dispatch services pursuant to the Tariff as included or includable in FERC Account Nos. 454 or 456. Such amount shall be certified in accordance with the second paragraph of this Attachment D.

R. 13.8 kV Transmission Facilities Revenue Requirement shall be the cost of operating 13.8 kV transmission facilities located within the City of Cambridge and calculated in accordance with Attachment D – 13.8 kV Transmission Rider.

13.8 kV Transmission Rider to Attachment D

ANNUAL 13.8 kV TRANSMISSION FACILITIES REVENUE REQUIREMENTS

The 13.8 kV Transmission Revenue Requirements for Cambridge will reflect the costs for its 13.8 kV Transmission System, including costs attributable to those incurred by the Company in owning, leasing, maintaining and supporting the 13.8 kV Transmission System net of revenues for transmission services provided under any other FERC accepted tariff or under any contract with other parties that provides reimbursement to the Company for 13.8 kV transmission related services. Under no circumstances shall the Company's Local Network Service rates, including these 13.8 kV Transmission Facilities Revenue Requirements, include costs that are charged through any other rate or tariff. The 13.8 kV Transmission Revenue Requirements will be an annual calculation based on the estimated costs for its 13.8 kV Transmission System during the Service Year. The Company shall make an annual informational filing with the FERC on or before May 31 of each year which shall include a True-up of estimated costs and revenues, and actual costs and revenues for the preceding Service Year. Actual costs will be determined using data required to be reported annually in the FERC Form 1 and recorded on the Company's books in accordance with FERC's Uniform System of Accounts; unless the use of other data, such as subaccount balances, is specifically required by the provisions below, in which case an independent certified public accountant, the "Auditor" as defined in Section 4, shall certify that the development, accuracy and application of such other data is in accordance with the provisions of this 13.8 kV Transmission Facilities Revenue Requirement included in the

Company's Local Network Service Embedded Cost Charge in accordance with the provisions of Attachment D, Section II.R. Such certification will be included with the annual informational filing along with adequate detail that supports the values contained within the True-up calculation. References to specific FERC Form1 pages, line numbers and columns included in this Local Service Schedule are based on the Company's 2004 Form 1. Subsequent FERC changes to Form 1 may be adopted to the extent they are consistent with the provisions and terms of this Local Service Schedule and not otherwise prohibited by FERC. This 13.8 kV Transmission Rider to Attachment D shall expire and have no further effect upon the effective date of the transfer of recovery of all costs hereunder to another tariff, as may be approved by the Massachusetts Department of Telecommunications and Energy, FERC or otherwise.

I. DEFINITIONS

Capitalized terms not otherwise defined in Section II.1 of the OATT or the Local Service Schedule and as used herein have the following definitions:

A. ALLOCATION FACTORS

1. <u>13.8 kV Transmission Wages and Salaries Allocation Factor</u> shall equal the ratio of 13.8 kV Transmission-related Direct Wages and Salaries as defined below to the Company's total direct wages and salaries including those of the affiliated companies as reported in the Company's FERC Form 1, page 354, line 25, column (b), and excluding administrative and

general wages and salaries as reported in the Company's FERC Form 1, page 354, line 24, column (b). All allocations and assignments of FERC Account balances shall be certified in accordance with the second paragraph of Attachment D.

2. 13.8 kV Plant Allocation Factor shall equal the ratio of the sum of 1) Total Investment in 13.8 kV Transmission Plant as defined below and 2) 13.8kv Transmission related Intangible and General Plant as defined below to Total Plant in Service excluding HQ leases. All allocations and assignments of FERC Account balances shall be certified in accordance with the second paragraph of Attachment D.

3. 13.8 kV Distribution Plant Allocation Factor shall equal the ratio of the sum of Total Investment in 13.8 kV Transmission Plant as defined below to Total Distribution Plant in Service.

B. TERMS

Administrative and General Expense shall equal the expenses as recorded in FERC Account Nos. 920-931 and 935, excluding FERC Account Nos. 924, 928 and 930.1.

Amortization of Gain on Reacquired Debt shall equal the amortization amount recorded in FERC Account No. 429.1.

Amortization of Loss on Reacquired Debt shall equal the expenses recorded in FERC Account No. 428.1.

Amortization of Investment Tax Credits shall equal the credits as recorded in FERC Account No. 411.4.

Depreciation Expense for 13.8 kV Transmission Plant shall equal the distribution depreciation expenses as recorded in FERC Account No. 403 as reported in the Company's annual FERC Form 1, page 336, line 8, column (b), multiplied by the 13.8 kV Distribution Plant Allocation Factor.

General Plant shall equal the gross plant balance as recorded in FERC Account Nos. 389-399.

General Plant Depreciation Expense shall equal the general plant expenses as recorded in FERC Account No. 403 as reported in the Company's annual FERC Form 1, page 336, line 9, column (b).

General Plant Depreciation Reserve shall equal the general reserve balance as recorded in FERC Account No. 108 as reported in the Company's annual FERC Form 1, page 219, line 27, column (e).

Intangible Plant shall equal the gross plant balance as recorded in FERC Account No. 303 as reported in the Company's annual FERC Form 1, page 205, line 4, column (g). The only allowable Intangible Plant for inclusion in the 13.8 kV Transmission rider are software, patent or rights costs. All allocations and assignments of FERC Account balances shall be certified in accordance with the second paragraph of Attachment D.

Intangible Plant Amortization Expense shall equal amortization expenses as recorded in FERC Account Nos. 404-405 as reported in the Company's annual FERC Form 1, page 336, line 1, column (f). The only allowable Intangible Plant Amortization Expense for inclusion in the 13.8 kV Transmission rider are software, patent or rights costs. All allocations and assignments of FERC Account balances shall be certified in accordance with the second paragraph of Attachment D.

Intangible Plant Amortization Reserve shall equal the amortization reserve balance as recorded in FERC Account No. 111. The only allowable Intangible Plant Amortization Reserve for inclusion in the 13.8 kV Transmission rider are software, patent or rights costs. All allocations and assignments of FERC Account balances shall be certified in accordance with the second paragraph of Attachment D.

Other Regulatory Assets/Liabilities - FAS 106 shall equal the net of the FAS 106 balance as recorded in FERC Account No. 182.3 and any FAS 106 balance as recorded in the FERC Account No. 254. All allocations and assignments of FERC Account balances shall be certified in accordance with the second paragraph of Attachment D.

Other Regulatory Assets/Liabilities - FAS 109 shall equal the net of the FAS 109 balance in FERC Account No. 182.3 and any FAS 109 balance as recorded in the FERC Account No. 254. All allocations and assignments of FERC Account balances shall be certified in accordance with the second paragraph of Attachment D.

Payroll Taxes shall equal those payroll expenses as recorded in the FERC Account No. 408.1. All allocations and assignments of FERC Account balances shall be certified in accordance with the second paragraph of Attachment D.

Prepayments shall equal the prepayment balance as recorded in FERC Account No. 165.

Property Insurance shall equal the expenses as recorded in FERC Account No. 924.

Total Accumulated Deferred Income Taxes shall equal the net of the deferred tax balance as recorded in FERC Account Nos. 281-283 and 190 for those balances that are directly related to 13.8 kV transmission, excluding those directly related to distribution or other businesses. All allocations and assignments of FERC Account balances shall be certified in accordance with the second paragraph of Attachment D.

Total Gain on Reacquired Debt shall equal the gain as recorded in FERC Account No. 257.

Total Loss on Reacquired Debt shall equal the expenses as recorded in FERC Account No. 189.

Total Municipal Tax Expense shall equal the municipal tax expenses as recorded in FERC Account No. 408.1 as reported in the Company's annual FERC Form 1, page 263, line 5, column (i).

Total Plant in Service shall equal the total gross plant balance as recorded in FERC Account Nos. 301-399 excluding HQ Leases recorded in those accounts.

Total 13.8 kV Transmission Depreciation Reserve shall equal the distribution reserve balance as recorded in FERC Account No. 108 as reported in the

Company's annual FERC Form 1, page 219, line 26, column (c), multiplied by the 13.8 kV Distribution Plant Allocation Factor.

13.8 kV Transmission Operation and Maintenance Expense shall equal the expenses as recorded in FERC Account Nos. 580-593 multiplied by the 13.8kv Distribution Plant Allocation Factor.

13.8 kV Transmission-related Direct Wages and Salaries shall be the total Distribution Wages & Salaries as reported in the Company's annual FERC Form 1, page 354, line 20, column (b), multiplied by the 13.8 kV Distribution Plant Allocation Factor.

13.8 kV Transmission Plant shall equal the 13.8 kV Gross Plant balance as recorded in FERC Account Nos. 360, 361, 362, 366 and 367 as determined by the Company's detailed property records systems. All allocations and assignments of FERC Account balances shall be certified in accordance with the second paragraph of Attachment D.

13.8 kV Transmission Plant Materials and Supplies shall equal the balance of distribution materials and supplies as recorded in FERC Account No. 154 as reported in the Company's annual FERC Form 1, page 227, line 9, column (c) multiplied by the 13.8 kV Plant Allocation Factor. All allocations and assignments of FERC Account balances shall be certified in accordance with the second paragraph of Attachment D.

II. CALCULATION OF 13.8 kV TRANSMISSION REVENUE REQUIREMENTS

The 13.8 kV Transmission Revenue Requirement shall equal the sum of (A) Return and Associated Income Taxes, (B) 13.8 kV Transmission Depreciation and Amortization Expense, (C) 13.8 kV Transmission Related Amortization of Loss on Reacquired Debt, (D) 13.8 kV Transmission Related Amortization of Investment Tax Credits, (E) 13.8 kV Transmission Related Municipal Tax Expense, (F) 13.8 kV Transmission Related Payroll Tax Expense, (G) 13.8 kV Transmission Operation and Maintenance Expense, (H) 13.8 kV Transmission Related Administrative and General Expenses, (I) 13.8 kV Transmission Support Revenue, minus (J) 13.8 kV Transmission Rents Received from Electric Property, minus (K) 13.8 kV Short-Term and Non-Firm Point-To-Point 13.8 kV Service Revenues.

A. Return and Associated Income Taxes shall equal the product of the 13.8 kV Transmission Investment Base and the Cost of Capital Rate.

1. 13.8 kV Transmission Investment Base

The 13.8 kV Transmission Investment Base will be the year end balances of (a) 13.8 kV Transmission Plant, plus (b) 13.8 kV Transmission Related

Intangible and General Plant, less (c) 13.8 kV Transmission Related Depreciation and Amortization Reserve, less (d) 13.8 kV Transmission Related Accumulated Deferred Taxes, plus (e) 13.8 kV Transmission Related Gain/Loss on Reacquired Debt, plus (f) Other 13.8 kV Regulatory Assets/Liabilities, plus (g) 13.8 kV Transmission Prepayments, plus (h) 13.8 kV Transmission Materials and Supplies, plus (i) 13.8 kV Transmission Related Cash Working Capital.

(a) <u>13.8 kV Transmission Plant</u> will equal the balance of the investment in 13.8 kV Transmission Plant.

(b) <u>13.8 kV Transmission Related Intangible and General Plant</u> shall equal the sum of the balance of investment in Intangible Plant and General Plant multiplied by the 13.8 kV Transmission Wages and Salaries Allocation Factor.

(c) <u>13.8 kV Transmission Related Depreciation and Amortization Reserve</u> shall equal the balance of the Total 13.8 kV Transmission Depreciation Reserve as defined above, plus the product of (i) the sum of the Intangible Plant Amortization Reserve and General Plant Depreciation Reserve and (ii) the 13.8 kV Transmission Wages and Salaries Allocation Factor. The only allowable

Intangible Plant and related expenses for inclusion in this 13.8 kV Transmission Rider are software, patent or rights costs. All allocations and assignments of FERC Account balances shall be certified in accordance with the second paragraph of Attachment D.

(d) 13.8 kV Transmission Related Accumulated Deferred Taxes shall equal the electric balance of Total 13.8 kV Accumulated Deferred Income Taxes (for those balances that are directly related to 13.8 kV transmission, plus the balances not directly related to other businesses), with the remaining accumulated deferred taxes not directly related to other businesses being allocated on the same basis used for the related rate base assets. All allocations and assignments of FERC Account balances shall be certified in accordance with the second paragraph of Attachment D.

(e) 13.8 kV Transmission Related Gain/Loss on Reacquired Debt shall equal the electric balance of Total Gain/Loss on Reacquired Debt multiplied by the 13.8 kV Plant Allocation Factor.

(f) Other Regulatory Assets/Liabilities shall equal the electric balance of any deferred rate recovery of FAS 106 expenses multiplied by the 13.8 kV Transmission Wages and Salaries Allocation Factor, plus the electric balance of FAS 109 multiplied by the 13.8 kV Plant Allocation Factor. All allocations and assignments of FERC Account balances shall be certified in accordance with the second paragraph of Attachment D.(g) 13.8 kV Transmission Prepayments shall equal the electric balance of Prepayments multiplied by the 13.8 kV Transmission Wages and Salaries Allocation Factor.

(h) 13.8 kV Transmission Materials and Supplies shall equal the electric balance of 13.8 kV Transmission Plant Materials and Supplies.

(i) 13.8 kV Transmission Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of the 13.8 kV Transmission Operation and Maintenance Expense included in II.G, and 13.8 kV Transmission Related Administrative and General Expenses included in II.H.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) the Weighted Cost of Capital, plus (b) Federal Income Tax plus (c) State Income Tax.

(a) The Weighted Cost of Capital will be calculated based upon the capital structure at the end of each year and will equal the sum of (i) and (ii) below.

(i) the long-term debt component, which equals the product of the actual weighted average embedded cost to maturity of the long-term debt then outstanding and the ratio that long-term debt is to the total capital.

(ii) the return on equity component shall be the product of the allowed ROE of the common equity and the ratio that common equity is to the total capital; provided that the common equity ratio shall be the Company's actual common equity ratio, but in no event shall the common equity ratio exceed 60 percent for 2005, 55 percent for 2006 and 50 percent for 2007 and beyond. The allowed ROE for all or any part of a Service Year shall be the ROE established pursuant to the provisions of the Federal Power Act for the Company under this Local Service Schedule, subject to refund as may be ordered by the Commission in the proceeding in which any ROE change is instituted.

(b) Federal Income Tax shall equal

$$\frac{(A+[(C+B)/D])(FT)}{1 - FT}$$

where FT is the Federal Income Tax Rate and A is the return on equity component, as determined in Section II.A.2.(a)(ii) above, B is 13.8 kV Transmission Related Amortization of Investment Tax Credits, as determined in Section II.D., below, C is the Equity AFUDC component of 13.8 kV Transmission Depreciation and Amortization Expense , as defined in Section II.B below, and D is 13.8 kV Transmission Investment Base, as determined in Section II.A.1., above.

(c) State Income Tax shall equal

$$\frac{(A+[(C+B)/D] + \text{Federal Income Tax})(ST)}{1 - ST}$$

where ST is the State Income Tax Rate, A is the return on equity component determined in Section II.A.2.(a)(ii) above, B is the 13.8 kV Amortization of Investment Tax Credits as determined in Section II.D. below, C is the equity AFUDC component of 13.8 kV Transmission Depreciation and Amortization Expense, as defined in Section II.B below, D is the 13.8 kV Transmission

Investment Base, as determined in II.A.1, above and Federal Income Tax is the rate determined in Section II.A.2.(b) above.

B. 13.8 kV Transmission Depreciation and Amortization Expense shall equal the sum of (i) the Depreciation Expense for 13.8 kV Transmission Plant and (ii) an allocation of Intangible Plant Amortization Expense and General Plant Depreciation Expense, which is calculated by multiplying the sum of (a) Intangible Plant Amortization Expense and (b) General Plant Depreciation Expenses by the 13.8 kV Transmission Wages and Salaries Allocation Factor. All allocations and assignments of FERC Account balances shall be certified in accordance with the second paragraph of Attachment D.

C. 13.8 kV Transmission Related Amortization of Gain/Loss on Reacquired Debt shall equal the electric Amortization of Gain/Loss on Reacquired Debt multiplied by the 13.8 kV Plant Allocation Factor.

D. 13.8 kV Transmission Related Amortization of Investment Tax Credits shall equal the electric Amortization of Investment Tax Credits multiplied by the 13.8 kV Plant Allocation Factor.

E. 13.8 kV Transmission Related Municipal Tax Expense shall equal the total electric municipal tax expense as reported in the Company's FERC Form 1, page

263, line 5, Local Real Estate and Personal Property Taxes, column (i), multiplied by the 13.8 kV Plant Allocation Factor.

F. 13.8 kV Transmission Related Payroll Tax Expense shall equal the total electric payroll tax expense as reported in the Company's FERC Form 1, page 263, Service Company Allocations and Capitalization, column (i), multiplied by the 13.8 kV Transmission Wages and Salaries Allocation Factor.

G. 13.8 kV Transmission Operation and Maintenance Expense shall equal the 13.8 kV Transmission Operation and Maintenance Expenses.

H. 13.8 kV Transmission Related Administrative and General Expenses shall equal the sum of the (1) Administrative and General Expense as defined above multiplied by the 13.8 kV Transmission Wages and Salaries Allocation Factor, and (2) Property Insurance as defined above multiplied by the 13.8 kV Plant Allocation Factor.

I. 13.8 kV Transmission Support Revenues shall equal the revenue received for 13.8 kV transmission support included or includable in FERC Account Nos. 454 or 456. All allocations and assignments of FERC Account balances shall be certified in accordance with the second paragraph of Attachment D.

J. 13.8 kV Transmission Rents Received from Electric Property shall equal any Account No. 454 Rents from electric property, associated with 13.8 kV Transmission Plant but not reflected as a credit in 13.8 kV Transmission Support Revenues in Section I. All allocations and assignments of FERC Account balances shall be certified in accordance with the second paragraph of Attachment D.

K. 13.8 kV Short-Term and Non-Firm Point-to-Point Service Revenues shall equal the applicable wheeling revenues received for Local Point-To-Point Service provided under this Local Service Schedule, including the 13.8 kV transmission component of the Company's Third-Party Sales, as recorded in Account Nos. 447 and 456. All allocations and assignments of FERC Account balances shall be certified in accordance with the second paragraph of Attachment D.

Cambridge Electric Light Company
Annual 13.8kV Transmission Facilities Revenue Requirements
Cost Year: 2005
Sheet 1

Col 1	Col 2	Col 3	Col 4	Col 5
Line	Description	Tariff Section	Amount	Reference
1	Investment Base	II		
2	13.8 kV Plant	II.A.1.a	$ 72,821,605	Sheet 3, Line 1, Col 8
3	13.8 kV Related Intangible and General Plant	II.A.1.b	1,970,913	Sheet 3, Line 4, Col 8
5	Total Gross 13.8 kV Plant		74,792,518	Sum Lines 2 thru 3
6	13.8 kV Related Depreciation and Amortization Reserve	II.A.1.c	(22,859,329)	Sheet 3, Line 9, Col 8
7	13.8 kV Related Accumulated Deferred Taxes	II.A.1.d	(10,300,807)	Sheet 3, Line 15, Col 8
8	Total Net 13.8 kV Plant		41,632,382	Sum Lines 5 thru 7
9	13.8 kV Related Gain/Loss on Reacquired Debt	II.A.1.e	-	Sheet 3, Line 16, Col 8
10	Other Regulatory Assets/Liabilities	II.A.1.f	295,799	Sheet 3, Line 20, Col 8
11	13.8 kV Prepayments	II.A.1.g	353,068	Sheet 3, Line 21, Col 8
12	13.8 kV Materials and Supplies	II.A.1.h	411,756	Sheet 3, Line 22, Col 8
13	13.8 kV Related Cash Working Capital	II.A.1.i	552,006	Sheet 3, Line 29, Col 8
14	Total Investment Base		$ 43,245,011	Sum Lines 8 thru 13
15	Revenue Requirements			
16	Return and Associated Income Taxes	II.A.2	$ 6,817,432	Sheet 2, Line 38, Col 4
17	13.8 kV Transmission Related Depreciation and Amortization Expense	II.B	2,259,571	Sheet 4, Line 5, Col 8
18	13.8 kV Transmission Related Related Amort. of Loss on Reacquired Debt	II.C	-	Sheet 4, Line 6, Col 8
19	13.8 kV Transmission Related Related Amortization of Investment Tax Credi	II.D	(21,514)	Sheet 4, Line 7, Col 8
20	13.8 kV Transmission Related Related Municipal Tax Expense	II.E	703,613	Sheet 4, Line 8, Col 8
21	13.8 kV Related Transmission Related Payroll Tax Expense	II.F	137,150	Sheet 4, Line 9, Col 8
22	13.8 kV Transmission Related Operation and Maintenance Expense	II.G	2,233,054	Sheet 4, Line 10, Col 8
23	13.8 kV Related Transmission Related Administrative and General Expenses	II.H	2,182,994	Sheet 4, Line 20, Col 8
24	13.8 kV Transmission Support Revenues	II.I	(891,002)	Sheet 6, Line 3, Col 5
25	13.8 kV Transmission Support Expense	II.J	-	Sheet 6
26	13.8 kV Transmission Rents Recieved from Electric Property	II.K	-	Sheet 6
27	13.8 kV Short-term & Non-Firm Point-to-Point Service Revenue	II.L	-	Sheet 6
28	Total 13.8 kV Revenue Requirements		**$ 13,421,298**	Sum Lines 16 thru 27

Cambridge Electric Light Company
Investment Return and Income Taxes
Cost Year: 2005
Sheet 2

Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9
Line	Description	Tariff Section	Balance	Ratio	Cost *	Weighted Cost	Equity Cost	Reference
1	Long Term Debt	II.A.2.a.i	25,000,000	40.00%	7.89%	3.16%		Page 112.24c
2	Preferred Stock		-	0.00%	0.00%	0.00%	0.00%	Page 112.3c
3	Common Equity	II.A.2.a.ii	89,763,255	60.00%	12.80%	7.68%	7.68%	Page 112.16c (less Line 2)
4	Total		114,763,255	100.00%		10.84%	7.68%	
5	Total Investment Base		43,245,011	Sheet 1, Line 14, Col 4				
6	**Cost of Capital Rate**	II.A.2						
7	(a) Weighted Cost of Capital	II.A.2.a	10.84%	Line 4, Col 7				
8	Return on Investment		**$ 4,687,759**	Line 5 * Line 7				
9	(b) Federal Income Tax	II.A.2.b	(A + [(C + B) / D]) (FT)					
10			1 - FT					
11	A = Equity Cost		7.68%	Line 4, Col 8				
12	B = Transmission Amortization of ITC		(21,514)	Sheet 4, Line 7, Col 8				
13	C = Equity AFUDC		-	Per Section II.B				
14	Total B + C		(21,514)	Lines 12 + 13				
15	D = Investment Base		$ 43,245,011	Line 5				
16	(B + C) / D		-0.05%	Line 14 / Line 15				
17	(A + [(C + B) / D]		7.63%	Lines 11 + 16				
18	FT = Federal Income Tax Rate		35.00%					
19	1 - FT		65.00%	1 - Line 18				
20	Federal Tax Factor		4.10860%	Line 17 * Line 18 / Line 19				
21	Federal Income Taxes		**$ 1,776,763**	Line 15 * Line 20				
20	(c) State Income Tax	II.A.2.c	(A + [(C + B) / D]) + Federal Income Tax) (ST)					
21			1 - ST					
22	A = Equity Cost		7.68%	Line 4, Col 8				
23	B = Transmission Amortization of ITC		(21,514)	Sheet 4, Line 7, Col 8				
24	C = Equity AFUDC		-	Per Section II.B				
25	Total B + C		(21,514)	Lines 23 + 24				
26	D = Investment Base		$ 43,245,011	Line 5				
27	(B + C) / D		-0.05%	Line 25 / Line 26				
28	(A + [(C + B) / D]		7.63%	Lines 26 + 27				
29	ST = State Income Tax Rate		6.50%					
30	1 - ST		93.50%	1 - line 29, Col 4				
31	Federal Tax Factor		4.11%	Line 20				
32	State Tax Factor		0.81607%	(Line 28 +Line 31) * Line 29 / Line 30				
33	State Income Taxes		**$ 352,909**	Line 26 * Line 32				
34	Investment Return and Income Taxes							
35	Return on Investment		$ 4,687,759	Line 8				
36	Federal Income Taxes		1,776,763	Line 21				
37	State Income Taxes		352,909	Line 33				
38	Total	II.A.2	**$ 6,817,432**	Sum Lines 35 thru 37				

* See Sheet 7, Col 15, Line 3 for Cost of LTD

Cambridge Electric Light Company
Investment Base
Cost Year: 2005
Sheet 3

Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9
Line	Description	Tariff Section	Total	Allocation Factor	Transmission Allocated (Col 4 x Col 5)	LNS Allocation Factor (b)	LNS Allocated (Col 6 x Col 7)	Reference
1	13.8 kV Transmission Plant	II.A.1.a	$ 153,267,084	47.5129%	$ 72,821,605	100.0000%	$ 72,821,605	Sheet 8, Line 17
2	Intangible Plant	II.A.1.b	2,774,261	32.4857% (a)	901,237	100.0000%	901,237	Page 205.5g
3	General Plant	II.A.1.b	3,292,765	32.4857% (a)	1,069,676	100.0000%	1,069,676	Page 207.90g
4	Total	II.A.1.b	6,067,026		1,970,913		1,970,913	Sum Lines 2 thru 3
5	13.8 kV Transmission Accumulated Depreciation & Amortization	II.A.1.c						
6	13.8 kV Transmission Accum Depreciation		(47,324,150)	47.5129% (d)	(22,485,066)	100.0000%	(22,485,066)	Page 219.26b
7	Intangible Plant Accum. Amortization		(1,139,569)	32.4857% (a)	(370,196)	100.0000%	(370,196)	Page 200.21b
8	General Plant Accum. Depreciation		(12,517)	32.4857% (a)	(4,066)	100.0000%	(4,066)	Page 219.27b
9	Total		(48,476,236)		(22,859,329)		(22,859,329)	Sum Lines 6 thru 8
10	13.8 kV Transmission Acc Def Taxes	II.A.1.d						
11	Accumulated Deferred Taxes (190)		7,530,939	13.6950% (e)	1,031,364	100.0000%	1,031,364	Page 234.2c (See Line 52)
12	Accumulated Deferred Taxes (281)		-			100.0000%	-	Page 273.8k
13	Accumulated Deferred Taxes (282)		(25,978,487)	37.7748% (c)	(9,813,326)	100.0000%	(9,813,326)	Page 275.2k
14	Accumulated Deferred Taxes (283)		(21,174,438)	7.1730% (f)	(1,518,845)	100.0000%	(1,518,845)	Page 277.3k (See Line 73)
15	Total		(39,621,986)		(10,300,807)		(10,300,807)	Sum Lines 11 thru 14
16	13.8 kV Gain/Loss on Reacquired Debt	II.A.1.e	-	37.7748% (c)	-	100.0000%	-	Page 111.81c + Page 113.61c
17	13.8 kV Other Regulatory Assets/Liabilities	II.A.1.f						
18	FAS 106 (182.3 & 254)		1,367,955	32.4857% (a)	444,389	100.0000%	444,389	Page 232 & 278
19	FAS 109 (182.3 & 254)		(393,358)	37.7748% (c)	(148,590)	100.0000%	(148,590)	Page 232 & 278
20	Total		974,597		295,799		295,799	Sum Lines 18 thru 19
21	13.8 kV Transmission Prepayments	II.A.1.g	1,086,844	32.4857% (a)	353,068	100.0000%	353,068	Page 111.57c
22	13.8 kV Transmission M&S	II.A.1.h	866,620	47.5129% (d)	411,756	100.0000%	411,756	Page 227.9c
23	13.8 kV Cash Working Capital	II.A.1.i						
24	Operation & Maintenance Expense						2,233,054	Sheet 1, Line 22, Col 4
25	Administrative & General Expense						2,182,994	Sheet 1, Line 23, Col 4
27	Total						4,416,048	Sum Lines 24 thru 25
28	Working Capital Factor						0.125	45 / 360
29	Total						552,006	Line 27 x Line 28

30	(a) 13.8 kV Wage & Salary Allocation Factor	32.4857%	Sheet 5, Line 8, Col 4
31	(b) LNS Allocation Factor	100.0000%	
32	(c) 13.8 kV Plant Allocation Factor	37.7748%	Sheet 5, Line 15, Col 4
33	(d) 13.8 kV Dist Plant Allocation Factor	47.5129%	Sheet 5, Line 19, Col 4

Line	Description	Total	Allocation Factor	Transmission Allocated	LNS Allocation Factor	LNS Allocated	Reference
34	(e) Accumulated Deferred Taxes (190)						
35	Sale of Generating Assets	1,200,565	0.0000%	-	100.0000%	-	
36	Demand Side Management revenue deferred	1,819,609	0.0000%	-	100.0000%	-	
37	Bonus depreciation state limitation	76,321	37.7748% (c)	28,830	100.0000%	28,830	
38	State loss limitation from 2000 net of amortization	186,028	37.7748% (c)	70,272	100.0000%	70,272	
39	Regulatory Assets	1,373,809	37.7748% (c)	518,954	100.0000%	518,954	
40	Charitable contributions	5,805	37.7748% (c)	2,193	100.0000%	2,193	
41	Mitigation incentive reserve unbilled	185,142	0.0000%	-	100.0000%	-	
42	NEPOOL	19,473	37.7748% (c)	7,356	100.0000%	7,356	
43	Stare benefit of federal change	15,857	37.7748% (c)	5,990	100.0000%	5,990	
44	Pension and PBOP costs	845,417	32.4857% (a)	274,639	100.0000%	274,639	
45	Provision for rate refund	1,289,216	0.0000%	-	100.0000%	-	
46	Sales tax abatement interest	45,647	37.7748% (c)	17,243	100.0000%	17,243	
47	Self insurance reserves	184,358	37.7748% (c)	69,641	100.0000%	69,641	
48	State net operating loss	60,982	37.7748% (c)	23,036	100.0000%	23,036	
49	Early lease retirement (Prudential)	40,666	32.4857% (a)	13,211	100.0000%	13,211	
50	Uncollectible accounts	180,653	0.0000%	-	100.0000%	-	
51	Stock incentive plan	1,391	0.0000%	-	100.0000%	-	
52	Total	7,530,939	13.6950%	1,031,364		1,031,364	Page 234.2c
53	(f) Account 283 - Non-Property						
54	Deferral of power costs	13,452,070	0.0000%	-	100.0000%	-	
55	Deferral of power costs-topside	(2,256,142)	0.0000%	-	100.0000%	-	
56	Regulatory assets PBOP	1,586,568	32.4857% (a)	515,407	100.0000%	515,407	
57	Cost to achieve expenditures	849,639	0.0000%	-	100.0000%	-	
58	Gain of sale of assets	4,189,415	0.0000%	-	100.0000%	-	
59	Federal appeals items	2,058,660	37.7748% (c)	777,655	100.0000%	777,655	
60	FAS 106 costs-Medicare Act	53,287	32.4857% (a)	17,311	100.0000%	17,311	
61	Environmental costs	174,756	37.7748% (c)	66,014	100.0000%	66,014	
62	FAS 109 reserve transfer	93,619	37.7748% (c)	35,364	100.0000%	35,364	
63	Interest accrued on potential tax deficiency	4,395	37.7748% (c)	1,660	100.0000%	1,660	
64	Investment in HEEC/HQ earnings	224,464	0.0000%	-	100.0000%	-	
65	ISO start-up costs deferred	10,836	37.7748% (c)	4,093	100.0000%	4,093	
66	Rate design adjustment	181,822	0.0000%	-	100.0000%	-	
67	Sale of generating assets	281,622	0.0000%	-	100.0000%	-	
68	State liability for Federal change 1997-1999	66,728	37.7748% (c)	25,206	100.0000%	25,206	
69	RAAC deferred revenue	1,152	0.0000%	-	100.0000%	-	
70	Interest on state and municipal accounts	7,431	37.7748% (c)	2,807	100.0000%	2,807	
71	FAS 109 Other	(285,486)	37.7748% (c)	(107,842)	100.0000%	(107,842)	
72	Other items	479,602	37.7748% (c)	181,169	100.0000%	181,169	
73	Total	21,174,438		1,518,845		1,518,845	Page 277.3k

Cambridge Electric Light Company
Transmission Expenses
Cost Year: 2005
Sheet 4

Col 1	Col 2	Col 3	Col 4	Col 5		Col 6	Col 7	Col 8	Col 9
Line	Description	Tariff Section	Total	Allocation Factor		Transmission Allocated	LNS Allocation Factor (b)	LNS Allocated	Reference
						(Col 4 x Col 5)		(Col 6 x Col 7)	
1	13.8 kV Depreciation & Amortization Expense	II.B							
2	13.8 kV Transmission Plant Depreciation	II.B.i	$ 4,343,709	47.5129%	(d)	$ 2,063,821	100.0000%	$ 2,063,821	Page 336.8b
3	Intangible Plant Amortization	II.B.ii	528,332	32.4857%	(a)	171,632	100.0000%	171,632	Page 336.1f
4	General Plant Depreciation	II.B.ii	74,240	32.4857%	(a)	24,117	100.0000%	24,117	Page 336.9b
5	Total		4,946,281			2,259,571		2,259,571	Sum Lines 2 thru 4
6	Amortization of Gain/Loss on Reacquired Debt	II.C	-	37.7748%	(c)	-	100.0000%	-	Page 117.64c + Page 117.66c
7	Amortization of Investment Tax Credits	II.D	(56,952)	37.7748%	(c)	(21,514)	100.0000%	(21,514)	Page 266.8f
8	Municipal Tax Expense	II.E	1,862,652	37.7748%	(c)	703,613	100.0000%	703,613	Page 263.5i
9	Payroll Taxes	II.F	422,187	32.4857%	(a)	137,150	100.0000%	137,150	Page 263.7i + Page 263.10i
10	13.8 kV Transmission Operations & Maintenance	II.G	4,699,891	47.5129%	(d)	2,233,054	100.0000%	2,233,054	Page 322.126b
11	Transmission Administrative & General	II.H							
12	Administrative and General		7,244,449						Page 323.168b
13	Property Insurance (924)		(37,247)						Page 323.156b
14	Regulatory Commission Expense (928)		(495,635)						Page 323.160b
15	General Advertising Expense (930.1)		(35,008)						Page 323.162b
16	Sub-Total		6,676,559	32.4857%	(a)	2,168,924	100.0000%	2,168,924	Sum Lines 12 thru 15
17	Property Insurance (924)		37,247	37.7748%	(c)	14,070	100.0000%	14,070	See Line 13
18	Regulatory Commission Expense (928)		495,635	0.0000%		-	100.0000%	-	See Line 14
19	General Advertising Expense (930.1)		35,008	0.0000%		-	100.0000%	-	See Line 15
20	Total		7,244,449			2,182,994		2,182,994	Sum Lines 16 thru 19

21	(a) 13.8 kV Wage & Salary Allocation Factor	32.4857%	Sheet 5, Line 8, Col 4
22	(b) LNS Allocation Factor	100.0000%	
23	(c) 13.8 kV Plant Allocation Factor	37.7748%	Sheet 5, Line 15, Col 4
24	(d) 13.8 kV Distribution Plant Allocation Factor	47.5129%	Sheet 5, Line 19, Col 4

Cambridge Electric Light Company
Allocation Factors
Cost Year: 2005
Sheet 5

Col 1	Col 2	Col 3	Col 4	Col 5
Line	Description	Tariff Section	Amount	Reference
1	**13.8 kV Wages and Salaries Allocation Factor**	I.A.1		
2	Distribution Wages & Salaries		$ 3,443,852	Page 354.20b
3	13.8 kV Distribution Plant Allocation Factor		47.5129%	Line 19
4	13.8 kV Transmission Wages & Salaries		$ 1,636,273	Line 2 x Line 3
5	Total Wages and Salaries		6,427,080	Page 354.25b
6	Administrative and General Salaries		1,390,170	Page 354.24b
7	Net Wages and Salaries		$ 5,036,910	Line 5 - Line 6
8	Allocation Factor		**32.4857%**	Line 4 / Line 7
9	**13.8 kV Plant Allocation Factor**	I.A.2		
10	13.8 kV Transmission Plant		$ 72,821,605	Sheet 3, Line 1, Col 8
11	13.8 kV Transmission Related Intangible Plant		901,237	Sheet 3, Line 2, Col 8
12	13.8 kV Transmission Related General Plant		1,069,676	Sheet 3, Line 3, Col 8
13	Total 13.8 kV Transmission Related Plant		$ 74,792,518	Sum Lines 10 thru 12
14	Total Plant in Service		$ 197,995,707	Page 207.95g
15	Allocation Factor		**37.7748%**	Line 13 / Line 14
16	**13.8 kV Distribution Plant Allocation Factor**	I.A.3		
17	13.8 kV Transmission Plant		$ 72,821,605	Sheet 8, Line 17, Col 6
18	Total Distribution Plant in Service		$ 153,267,084	Page 207.75g
19	Allocation Factor		**47.5129%**	Line 17 / Line 18

Cambridge Electric Light Company
13.8 kV Transmission Support Revenue Detail
Cost Year: 2005
Sheet 6

Col 1 Line	Col 2 Description	Col 3 Tariff Section	Col 4 Amount	Col 5 Includable Amount	Col 6 Reference
1	Transmission Charges - Muni (456122 Belmont)		(1,031,006)	(762,944)	Remaining amount credited in 115 kV
2	Transmission Charges - Muni (456122 MBTA)		(200,274)	(128,058)	Remaining amount credited in 115 kV
3	Total		(1,231,280)	(891,002)	

Cambridge Electric Light Company
Cost of Long Term Debt
Cost Year: 2005
Sheet 7

Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12	Col 13	Col 14	Col 15	Col 16
	Long Term Debt					Principal	Sinking	Pro Forma		Total Debt	Call Premium	Net Proceeds			
	Series	Dated	Term (Years)	Coupon Rate	Original Issue	Amount Outstanding	Fund Requiremen	Amount Outstanding	Percent of Total	Disc & Exp	on Debt	to Company	Cost to Maturity	Weighted Cost	Reference
								Col 7 - Col 8	Col 9 / Col 9 Total			Col 6 - Col 11 - Col 12	Col 5 + (((Col 11 + Col 12) /	Col 10 * Col 14	
1	Series H - 8.70%	03/01/92	15	8.70%	$ 5,000,000	$ 5,000,000	$ -	$ 5,000,000	20.00%	$ 49,431	$ -	$ 4,950,569	8.77%	1.75%	Page 256 & 257, Line 4
2	Senior Note - 7.62%	11/24/99	15	7.62%	20,000,000	20,000,000	-	20,000,000	80.00%	149,269	-	$ 19,850,731	7.67%	6.14%	Page 256 & 257, Line 7
3	Total				$ 25,000,000	$ 25,000,000	$ -	$ 25,000,000	100.00%	$ 198,700	$ -	$ 24,801,300		7.89%	

Cambridge Electric Light Company
13.8 kV Plant Factors
Cost Year: 2005
Sheet 8

Col 1 Line	Col 2 Description	Col 3 Tariff Section	Col 4 Per Form 1	Col 5 Percent	Col 6 13.8 kV Plant *	Col 7 Reference
1	**13.8 kV Plant**	I.A.3		(Col 6 / Col 4)		
2	Land and Land Rights (360)		$ 237,789	36.2456%	$ 86,188	Page 207.60g
3	Structures and Improvements (361)		10,155,494	99.5934%	10,114,206	Page 207.61g
4	Station Equipment (362)		51,124,093	60.1388%	30,745,434	Page 207.62g
5	Storage Battery Equipment (363)		-	0.0000%	-	Page 207.63g
6	Poles, Towers and Fixtures (364)		2,770,926	0.0000%	-	Page 207.64g
7	Overhead Conductors and Devices (365)		6,271,103	0.0000%	-	Page 207.65g
8	Underground Conduit (366)		20,075,228	42.8000%	8,592,198	Page 207.66g
9	Underground Conductors and Devices (367)		46,197,578	50.4000%	23,283,579	Page 207.67g
10	Line Transformers (368)		4,280,893	0.0000%	-	Page 207.68g
11	Services (369)		7,403,386	0.0000%	-	Page 207.69g
12	Meters (370)		3,941,065	0.0000%	-	Page 207.70g
13	Installations on Customer Premises (371)		-	0.0000%	-	Page 207.71g
14	Leased Property on Customer Premises (372)		-	0.0000%	-	Page 207.72g
15	Streetlights (373)		809,529	0.0000%	-	Page 207.73g
16	Asset Retirement Costs for Dist Plant (374)		-	0.0000%	-	Page 207.74g
17	Total Distribution Plant		$ 153,267,084	47.5129%	$72,821,605	Sum Lines 2 thru 16

Cambridge Electric Light Company

Rate Design Worksheet - Merger: 13.8 kV Transfer

R-1	Settlement May 1, 2006	Merger Change	Merger Rates	Percent Change
Customer	$ 6.87		$ 6.87	
Energy Charges				
Distribution	$ 0.02545	$ 0.00920	$ 0.03465	36.1%
Transmission	$ 0.03026	$ (0.00920)	$ 0.02106	-30.4%
Transition	$ 0.01489		$ 0.01489	
Transition Rate Adj	$ (0.00077)		$ (0.00077)	
Pension Adj	$ 0.00086		$ 0.00086	
RAAF	$ 0.00013		$ 0.00013	
DSM	$ 0.00250		$ 0.00250	
Renewables	$ 0.00050		$ 0.00050	
Default Service Adj.	$ 0.00245		$ 0.00245	
Default Service	$ 0.12045		$ 0.12045	
Total Energy	$ 0.19672	$ -	$ 0.19672	0.0%

R-2	Settlement May 1, 2006	Merger Change	Merger Rates	Percent Change
Customer	$ 4.51		$ 4.51	
Energy Charges				
Distribution	$ 0.00386	$ 0.00920	$ 0.01306	238.4%
Transmission	$ 0.03026	$ (0.00920)	$ 0.02106	-30.4%
Transition	$ 0.01489		$ 0.01489	
Transition Rate Adj	$ (0.00068)		$ (0.00068)	
Pension Adj	$ 0.00086		$ 0.00086	
RAAF	$ 0.00013		$ 0.00013	
DSM	$ 0.00250		$ 0.00250	
Renewables	$ 0.00050		$ 0.00050	
Default Service Adj.	$ 0.00245		$ 0.00245	
Default Service	$ 0.12045		$ 0.12045	
Total Energy	$ 0.17522	$ -	$ 0.17522	0.0%

R-3	Settlement May 1, 2006	Merger Change	Merger Rates	Percent Change
Customer	$ 7.77			
Energy Charges				
Distribution	$ 0.03037	$ 0.01082	$ 0.04119	35.6%
Transmission	$ 0.03560	$ (0.01082)	$ 0.02478	-30.4%
Transition	$ 0.01489		$ 0.01489	
Transition Rate Adj	$ (0.00100)		$ (0.00100)	
Pension Adj	$ 0.00086		$ 0.00086	
RAAF	$ 0.00013		$ 0.00013	
DSM	$ 0.00250		$ 0.00250	
Renewables	$ 0.00050		$ 0.00050	
Default Service Adj.	$ 0.00245		$ 0.00245	
Default Service	$ 0.12045		$ 0.12045	
Total Energy	$ 0.20675	$ -	$ 0.20675	0.0%

R-4	Settlement May 1, 2006	Merger Change	Merger Rates	Percent Change
Customer	$ 5.09		$ 5.09	
Energy Charges				
Distribution	$ 0.00625	$ 0.01082	$ 0.01707	173.1%
Transmission	$ 0.03560	$ (0.01082)	$ 0.02478	-30.4%
Transition	$ 0.01489		$ 0.01489	
Transition Rate Adj	$ (0.00058)		$ (0.00058)	
Pension Adj	$ 0.00086		$ 0.00086	
RAAF	$ 0.00013		$ 0.00013	
DSM	$ 0.00250		$ 0.00250	
Renewables	$ 0.00050		$ 0.00050	
Default Service Adj.	$ 0.00245		$ 0.00245	
Default Service	$ 0.12045		$ 0.12045	
Total Energy	$ 0.18305	$ -	$ 0.18305	0.0%

Cambridge Electric Light Company

Rate Design Worksheet - Merger: 13.8 kV Transfer

R-5	Settlement May 1, 2006	Merger Change	Merger Rates	Percent Change
Customer	$ 10.47		$ 10.47	0.0%
Energy Charges				
Distribution				
Peak	$ 0.09392	$ 0.02065	$ 0.11457	22.0%
Low Load	$ 0.01209		$ 0.01209	
Transmission				
Peak	$ 0.06794	$ (0.02065)	$ 0.04729	-30.4%
Low Load	$ -		$ -	
Transition				
Peak	$ 0.02711		$ 0.02711	
Low Load	$ 0.01139		$ 0.01139	
Transition Rate Adj				
Peak	$ (0.00154)		$ (0.00154)	
Low Load	$ (0.00199)		$ (0.00199)	
Pension Adj	$ 0.00086		$ 0.00086	
RAAF	$ 0.00013		$ 0.00013	
DSM	$ 0.00250		$ 0.00250	
Renewables	$ 0.00050		$ 0.00050	
Default Service Adj.	$ 0.00245		$ 0.00245	
Default Service	$ 0.12045		$ 0.12045	
Total Peak Energy	$ 0.31432	$ -	$ 0.31432	0.0%
Total Low Load Energy	$ 0.14838	$ -	$ 0.14838	0.0%

R-6	Settlement May 1, 2006	Merger Change	Merger Rates	Percent Change
Customer	$ 11.37		$ 11.37	0.0%
Energy Charges				
Distribution				
Peak	$ 0.12393	$ 0.04084	$ 0.16477	33.0%
Low Load	$ 0.01715		$ 0.01715	
Transmission	$ -			
Peak	$ 0.13436	$ (0.04084)	$ 0.09352	-30.4%
Low Load	$ -		$ -	
Transition	$ -			
Peak	$ 0.08697		$ 0.08697	
Low Load	$ 0.00940		$ 0.00940	
Transition Rate Adj	$ -			
Peak	$ 0.01182		$ 0.01182	
Low Load	$ 0.01182		$ 0.01182	
Pension Adj	$ 0.00086		$ 0.00086	
RAAF	$ 0.00013		$ 0.00013	
DSM	$ 0.00250		$ 0.00250	
Renewables	$ 0.00050		$ 0.00050	
Default Service Adj.	$ 0.00245		$ 0.00245	
Default Service	$ 0.12045		$ 0.12045	
Total Peak Energy	$ 0.48397	$ -	$ 0.48397	0.0%
Total Low Load Energy	$ 0.16526	$ -	$ 0.16526	0.0%

Cambridge Electric Light Company

Rate Design Worksheet - Merger: 13.8 kV Transfer

G-0 (Non-Demand)	Settlement May 1, 2006	Merger Change	Merger Rates	Percent Change
Customer	$ 4.62		$ 4.62	
Energy Charges				
Distribution	$ 0.02186	$ 0.00862	$ 0.03048	39.4%
Transmission	$ 0.02837	$ (0.00862)	$ 0.01975	-30.4%
Transition	$ 0.01489		$ 0.01489	
Transition Rate Adj	$ (0.00072)		$ (0.00072)	
Pension Adj	$ 0.00086		$ 0.00086	
RAAF	$ 0.00013		$ 0.00013	
DSM	$ 0.00250		$ 0.00250	
Renewables	$ 0.00050		$ 0.00050	
Default Service Adj.	$ 0.00245		$ 0.00245	
Default Service	$ 0.11620		$ 0.11620	
Total Energy	$ 0.18704	$ -	$ 0.18704	0.0%

G-1	Settlement May 1, 2006	Merger Change	Merger Rates	Percent Change
Customer	$ 7.32		$ 7.32	
Demand Charges < 10 kW				
Distribution < 10 kW	$ 1.29	$ 2.57	$ 3.86	199.4%
Transition < 10 kW	$ 4.36		$ 4.36	
Transmission	$ 8.44	$ (2.57)	$ 5.87	-30.5%
Total Demand Charges < 10 kW	$ 14.09	$ -	$ 14.09	0.0%
Demand Charges > 10 kW				
Distribution > 10 kW	$ 4.54	$ 2.56	$ 7.10	56.4%
Transition > 10 kw	$ 4.36		$ 4.36	
Transmission	$ 8.44	$ (2.56)	$ 5.88	-30.3%
Total Demand Charges > 10 kW	$ 17.34	$ -	$ 17.34	0.0%
Energy Charges				
Distribution (Energy)	$ 0.00783		$ 0.00783	
Transition Rate Adj	$ (0.00022)		$ (0.00022)	
Transition (Energy)	$ -		$ -	
Pension Adj	$ 0.00086		$ 0.00086	
RAAF	$ 0.00013		$ 0.00013	
DSM	$ 0.00250		$ 0.00250	
Renewables	$ 0.00050		$ 0.00050	
Default Service Adj.	$ 0.00245		$ 0.00245	
Default Service	$ 0.11620		$ 0.11620	
Total Energy Charges	$ 0.13025		$ 0.13025	0.0%

Cambridge Electric Light Company

Rate Design Worksheet - Merger: 13.8 kV Transfer

G-2	Settlement May 1, 2006	Merger Change	Merger Rates	Percent Change
Customer	$ 90.00		$ 90.00	
Demand Charges < 100 kva				
Distribution < 100 kva	$ 1.09	$ 1.76	$ 2.85	161.5%
Transmission < 100 kva	$ 5.80	$ (1.76)	$ 4.04	-30.4%
Transition < 100 kva	$ 1.27		$ 1.27	0.0%
Total Demand Charges < 100 kva	$ 8.16	$ -	$ 8.16	0.0%
Demand Charges > 100 kva				
Distribution > 100 kva	$ 2.06	$ 3.64	$ 5.70	176.7%
Transmission > 100 kva	$ 11.96	$ (3.64)	$ 8.32	-30.4%
Transition > 100 kva	$ 1.27		$ 1.27	0.0%
Total Demand Charges > 100 kva	$ 15.29	$ -	$ 15.29	0.0%
Energy Charges - Peak				
Distribution (Energy)	$ 0.00604		$ 0.00604	
Transition (Energy)	$ 0.01672		$ 0.01672	
Transition Rate Adj	$ 0.00031		$ 0.00031	
Pension Adj	$ 0.00086		$ 0.00086	
RAAF	$ 0.00013		$ 0.00013	
DSM	$ 0.00250		$ 0.00250	
Renewables	$ 0.00050		$ 0.00050	
Default Service Adj.	$ 0.00245		$ 0.00245	
Default Service	$ 0.16890		$ 0.16890	
Total Energy Charges - Peak	$ 0.19841		$ 0.19841	0.0%
Energy Charges - Low A				
Distribution (Energy)	$ 0.00604		$ 0.00604	27.7%
Transition (Energy)	$ 0.00960		$ 0.00960	
Transition Rate Adj	$ 0.00031		$ 0.00031	
Pension Adj	$ 0.00086		$ 0.00086	
RAAF	$ 0.00013		$ 0.00013	
DSM	$ 0.00250		$ 0.00250	
Renewables	$ 0.00050		$ 0.00050	
Default Service Adj.	$ 0.00245		$ 0.00245	
Default Service	$ 0.16890		$ 0.16890	
Total Energy Charges - Low A	$ 0.19129		$ 0.19129	0.0%
Energy Charges - Low B				
Distribution (Energy)	$ 0.00604		$ 0.00604	
Transition (Energy)	$ 0.00960		$ 0.00960	
Transition Rate Adj	$ 0.00031		$ 0.00031	
Pension Adj	$ 0.00086		$ 0.00086	
RAAF	$ 0.00013		$ 0.00013	
DSM	$ 0.00250		$ 0.00250	
Renewables	$ 0.00050		$ 0.00050	
Default Service Adj.	$ 0.00245		$ 0.00245	
Default Service	$ 0.16890		$ 0.16890	
Total Energy Charges - Low B	$ 0.19129		$ 0.19129	

Cambridge Electric Light Company

Rate Design Worksheet - Merger: 13.8 kV Transfer

G-3	Settlement May 1, 2006	Merger Change	Merger Rates	Percent Change
Customer	$ 90.00		$ 90.00	0.0%
Demand Charges < 100 kva				
Distribution < 100 kva	$ -	$ 116.15	$ 116.15	
Transmission < 100 kva	$ 382.13	$ (116.15)	$ 265.98	-30.4%
Transition < 100 kva	$ 237.00		$ 237.00	
Interruptible Credit	$ (0.83)		$ (0.83)	
Total Demand Charges < 100 kva	$ 618.30	$ -	$ 618.30	0.0%
Demand Charges > 100 kva				
Distribution > 100 kva	$ 2.08	$ 2.22	$ 4.30	106.9%
Transmission > 100 kva	$ 7.31	$ (2.22)	$ 5.09	-30.4%
Transition > 100 kva	$ 1.68		$ 1.68	
Interruptible Credit	$ (0.83)		$ (0.83)	
Total Demand Charges > 100 kva	$ 10.24	$ -	$ 10.24	0.0%
Energy Charges				
Distribution (Energy)	$ (0.00015)		$ (0.00015)	
Transition (Energy)	$ 0.01099		$ 0.01099	
Transition Rate Adj	$ 0.00103		$ 0.00103	
Pension Adj	$ 0.00086		$ 0.00086	
RAAF	$ 0.00013		$ 0.00013	
DSM	$ 0.00250		$ 0.00250	
Renewables	$ 0.00050		$ 0.00050	
Default Service Adj.	$ 0.00245		$ 0.00245	
Default Service	$ 0.16890		$ 0.16890	
Total Energy Charges	$ 0.18721	$ -	$ 0.18721	0.0%

G-4	Settlement May 1, 2006	Merger Change	Merger Rates	Percent Change
Customer	$ 10.92		$ 10.92	
Demand Charges - Peak				
Distribution (Demand)	$ 1.72	$ 2.51	$ 4.23	146.1%
Transmission (Demand)	$ 8.25	$ (2.51)	$ 5.74	-30.4%
Transition (Demand)	$ 6.02		$ 6.02	
Transition Rate Adj	$ (0.18)		$ (0.18)	
Total Demand Charges - Peak	$ 15.80	$ -	$ 15.80	0.0%
Energy Charges				
Distribution (Energy)	$ 0.00695		$ 0.00695	
Transistion (Energy)	$ -		$ -	
Pension Adj	$ 0.00086		$ 0.00086	
RAAF	$ 0.00013		$ 0.00013	
DSM	$ 0.00250		$ 0.00250	
Renewables	$ 0.00050		$ 0.00050	
Default Service Adj.	$ 0.00245		$ 0.00245	
Default Service	$ 0.11620		$ 0.11620	
Total Energy Charges	$ 0.12959	$ -	$ 0.12959	0.0%

Cambridge Electric Light Company

Rate Design Worksheet - Merger: 13.8 kV Transfer

G-5	Settlement May 1, 2006	Merger Change	Merger Rates	Percent Change
Customer	$ 7.20		$ 7.20	
Energy Charges < 5000 kWh				
Distribution	$ 0.00495	$ 0.00788	$ 0.01283	159.2%
Transmission	$ 0.02591	$ (0.00788)	$ 0.01803	-30.4%
Transition	$ 0.01489		$ 0.01489	
Transition Rate Adj	$ (0.00113)		$ (0.00113)	
Pension Adj	$ 0.00086		$ 0.00086	
RAAF	$ 0.00013		$ 0.00013	
DSM	$ 0.00250		$ 0.00250	
Renewables	$ 0.00050		$ 0.00050	
Default Service Adj.	$ 0.00245		$ 0.00245	
Default Service	$ 0.11620		$ 0.11620	
Total Energy Charges < 5000 kWh	$ 0.16726	$ -	$ 0.16726	0.0%
Energy Charges > 5000 kWh				
Distribution	$ 0.01053	$ 0.01010	$ 0.02063	95.9%
Transmission	$ 0.03322	$ (0.01010)	$ 0.02312	-30.4%
Transition	$ 0.01489		$ 0.01489	
Transition Rate Adj	$ (0.00113)		$ (0.00113)	
Pension Adj	$ 0.00086		$ 0.00086	
RAAF	$ 0.00013		$ 0.00013	
DSM	$ 0.00250		$ 0.00250	
Renewables	$ 0.00050		$ 0.00050	
Default Service Adj.	$ 0.00245		$ 0.00245	
Default Service	$ 0.11620		$ 0.11620	
Total Energy Charges > 5000 kWh	$ 0.18015	$ -	$ 0.18015	0.0%

G-6 (Non-Demand)	Settlement May 1, 2006	Merger Change	Merger Rates	Percent Change
Customer	$ 8.22		$ 8.22	
Energy Charges - Peak				
Distribution	$ 0.05169	$ 0.02924	$ 0.08093	56.6%
Transmission	$ 0.09620	$ (0.02924)	$ 0.06696	-30.4%
Transition	$ 0.02802		$ 0.02802	
Transition Rate Adj	$ (0.00072)		$ (0.00072)	
Pension Adj	$ 0.00086		$ 0.00086	
RAAF	$ 0.00013		$ 0.00013	
DSM	$ 0.00250		$ 0.00250	
Renewables	$ 0.00050		$ 0.00050	
Default Service Adj.	$ 0.00245		$ 0.00245	
Default Service	$ 0.11620		$ 0.11620	
Total Energy Charges - Peak	$ 0.29783	$ -	$ 0.29783	0.0%
Energy Charges - Low Load				
Distribution	$ 0.01161	$ -	$ 0.01161	0.0%
Transmission	$ -	$ -	$ -	
Transition	$ 0.00987		$ 0.00987	
Transition Rate Adj	$ (0.00072)		$ (0.00072)	
Pension Adj	$ 0.00086		$ 0.00086	
RAAF	$ 0.00013		$ 0.00013	
DSM	$ 0.00250		$ 0.00250	
Renewables	$ 0.00050		$ 0.00050	
Default Service Adj.	$ 0.00245		$ 0.00245	
Default Service	$ 0.11620		$ 0.11620	
Total Energy Charges - Low Load	$ 0.14340	$ -	$ 0.14340	0.0%

Cambridge Electric Light Company

Rate Design Worksheet - Merger: 13.8 kV Transfer

S-1/S-2	Settlement May 1, 2006	Merger Change	Merger Rates	Percent Change
Customer Charge	$ -		$ -	
Energy Charges				
Distribution	$ 0.03218	$ 0.00719	$ 0.03937	22.3%
Renewables	$ 0.00050		$ 0.00050	
Transmission	$ 0.02367	$ (0.00719)	$ 0.01648	-30.4%
Transition	$ 0.01580		$ 0.01580	
Transition Rate Adj.	$ (0.00158)		$ (0.00158)	
Pension Adj. Factor	$ 0.00086		$ 0.00086	
RAAF	$ 0.00013		$ 0.00013	
Default Service Adj	$ 0.00245		$ 0.00245	
Default Service	$ 0.11620		$ 0.11620	
Total Energy Charges	$ 0.19021	$ -	$ 0.19021	0.0%

STANDBY, SUPPLEMENTAL, MAINTENANCE	Settlement May 1, 2006	Merger Change	Merger Rates	Percent Change
Customer	$ 781.00		$ 781.00	
Standby Demand Charges - Peak				
Transmission Capacity Charge	$ 1.52	$ (0.46)	$ 1.06	-30.4%
Standby Capacity Charge	$ 7.07	$ 0.46	$ 7.53	6.5%
Standby Generation Charge	$ 3.03		$ 3.03	
Total Standby Demand Charges - Peak	$ 11.61	$ -	$ 11.61	0.0%
Demand Charges < 100 kva				
Suppl. Distribution < 100 kva	$ -	$ 116.15	$ 116.15	
Suppl. Transmission < 100 kva	$ 382.13	$ (116.15)	$ 265.98	-30.4%
Suppl. Transition < 100 kva	$ 237.00	$ -	$ 237.00	
Standby - Reserve	$ 0.36	$ -	$ 0.36	
Total Demand Charges < 100 kva	$ 619.49	$ -	$ 619.49	0.0%
Demand Charges > 100 kva				
Suppl. Distribution >100 kva	2.07	$ 2.22	$ 4.29	107.2%
Suppl. Transmission >100 kva	7.31	$ (2.22)	$ 5.09	-30.4%
Suppl. Transition > 100 kva	1.68		$ 1.68	
Standby - Reserve	0.36		$ 0.36	
Total Demand Charges > 100 kva	$ 11.43	$ -	$ 11.43	0.0%
Energy Charges				
Suppl. Transition	$ 0.01099		$ 0.01099	
Standby Transition	$ 0.01403		$ 0.01403	
Suppl. Transition Rate Adj.	$ (0.00088)		$ (0.00088)	
Standby Transition Rate Adj.	$ (0.00088)		$ (0.00088)	
Pension Adj.	$ 0.00086		$ 0.00086	
RAAF	$ 0.00013		$ 0.00013	
DSM	$ 0.00250		$ 0.00250	
Renewables	$ 0.00050		$ 0.00050	
Default Service Adj.	$ 0.00245		$ 0.00245	
Suppl. Generation	$ 0.16890		$ 0.16890	
Standby Generation	$ 0.16890		$ 0.16890	
Total Energy Charges	$ 0.36750	$ -	$ 0.36750	0.0%

Cambridge Electric Light Company

Rate Design Worksheet - Merger: 13.8 kV Transfer

SB-G2	Settlement May 1, 2006	Merger Change	Merger Rates	Percent Change
Customer	$ 90.00		$ 90.00	
Demand Charges (Contract Demand < 1000 kva)				
Standby Distribution < 100 kVA	$ 2.00	$ 1.76	$ 3.76	27.7%
Standby Distribution > 100 kVA	$ 2.67	$ 3.64	$ 6.31	27.7%
Supplemental Transmission < 100 kva	$ 5.80	$ (1.76)	$ 4.04	-30.4%
Supplemental Transmission > 100 kva	$ 11.96	$ (3.64)	$ 8.32	-30.4%
Supplemental Distribution	$ 4.94	$ 3.64	$ 8.58	73.7%
Total Demand Charges (Contract Demand < 1000 kva)				
Demand Charges (Contract Demand >= 1000 kva)				
Standby Distribution < 100 kVA	$ 3.14	$ 1.76	$ 4.90	27.7%
Standby Distribution > 100 kVA	$ 4.20	$ 3.64	$ 7.84	27.7%
Supplemental Transmission < 100 kva	$ 5.80	$ (1.76)	$ 4.04	-30.4%
Supplemental Transmission > 100 kva	$ 11.96	$ (3.64)	$ 8.32	-30.4%
Supplemental Distribution	$ 4.94	$ 3.64	$ 8.58	73.7%
Total Demand Charges (Contract Demand >= 1000 kva)				
Energy Charges				
Transition (Energy)	$ 0.00960		$ 0.00960	
Transition Rate Adj	$ 0.00031		$ 0.00031	
Pension Adj	$ 0.00086		$ 0.00086	
RAAF	$ 0.00013		$ 0.00013	
DSM	$ 0.00250		$ 0.00250	
Renewables	$ 0.00050		$ 0.00050	
Total Energy Charges	$ 0.01390	$ -	$ 0.01390	0.0%

SB-G3	Settlement May 1, 2006	Merger Change	Merger Rates	Percent Change
Customer	$ 90.00		$ 90.00	
Demand Charges (Contract Demand < 1000 kva)				
Standby Distribution < 100 kVA	$ -	$ 116.15	$ 116.15	
Standby Distribution > 100 kVA	$ 0.79	$ 2.22	$ 3.01	49.4%
Supplemental Transmission < 100 kva	$ 382.13	$ (116.15)	$ 265.98	-30.4%
Supplemental Transmission > 100 kva	$ 7.31	$ (2.22)	$ 5.09	-30.4%
Supplemental Distribution	$ 2.08	$ 2.22	$ 4.30	106.9%
Total Demand Charges (Contract Demand < 1000 kva)				
Demand Charges (Contract Demand >= 1000 kva)				
Standby Distribution < 100 kVA	$ -	$ 116.15	$ 116.15	
Standby Distribution > 100 kVA	$ 1.79	$ 2.22	$ 4.01	49.4%
Supplemental Transmission < 100 kva	$ 382.13	$ (116.15)	$ 265.98	-30.4%
Supplemental Transmission > 100 kva	$ 7.31	$ (2.22)	$ 5.09	-30.4%
Supplemental Distribution	$ 2.08	$ 2.22	$ 4.30	106.9%
Total Demand Charges (Contract Demand >= 1000 kva)				
Energy Charges				
Transition (Energy)	$ 0.00956		$ 0.00956	
Transition Rate Adj	$ 0.00103		$ 0.00103	
Pension Adj	$ 0.00086		$ 0.00086	
RAAF	$ 0.00013		$ 0.00013	
DSM	$ 0.00250		$ 0.00250	
Renewables	$ 0.00050		$ 0.00050	
Total Energy Charges	$ 0.01458	$ -	$ 0.01458	0.0%

Cambridge Electric Light Company

Rate Design Worksheet - Merger: 13.8 kV Transfer

MIT Mag Lab	Settlement May 1, 2006	Merger Change	Merger Rates	Percent Change
Customer	$ 430.00		$ 430.00	
Demand Charges				
Distribution	$ 0.112	$ 0.66	$ 0.77	589.3%
Transmission	$ 2.18	$ (0.66)	$ 1.52	-30.3%
Transition	$ 0.22		$ 0.22	
Total Demand Charges	$ 2.51	$ -	$ 2.51	0.0%
Pulse Demand Charges				
Distribution	$ 0.095	$ 0.08	$ 0.18	84.2%
Transmission	$ 0.252	$ (0.08)	$ 0.17	-31.7%
Transition	$ -		$ -	
Total Pulse Demand Charges	$ 0.347	$ -	$ 0.35	0.0%
Energy Charges				
Distribution	$ (0.00015)		$ (0.00015)	
Transition (Energy)	$ -		$ -	
Transition Rate Adj	$ -		$ -	
Pension Adj	$ 0.00086		$ 0.00086	
RAAF	$ 0.00013		$ 0.00013	1202.8%
DSM	$ 0.00250		$ 0.00250	
Renewables	$ 0.00050		$ 0.00050	
Total Energy Charges	$ 0.00384	$ -	$ 0.00384	0.0%

Commonwealth Electric Company
Plant Balances as of 6/30/2005

Col. A	Col. B	Col. C	Col. D. Old	Col. E
	Intangibles	**Plant Balance**	**Depr. Rate (1)**	**Annual Accrual**
303	Computer Software	12,900,396.00	20.00%	2,580,079.20
	Distribution			
360	Land	2,888,527.00	0.00%	0.00
361	Structures	1,615,057.00	2.97%	47,967.19
362	Station Equipment	55,626,753.00	3.14%	1,746,680.04
364	Poles & Fixture	103,030,570.00	3.61%	3,719,403.58
365	Overhead Conductors	141,412,633.00	2.63%	3,719,152.25
366	Underground Conduit	33,309,786.00	2.12%	706,167.46
367	Underground Conductors	83,225,952.00	3.46%	2,879,617.94
368	Line Transformers	87,980,557.00	2.70%	2,375,475.04
369	Services	47,121,693.00	3.83%	1,804,760.84
370	Meters	28,330,888.00	3.23%	915,087.68
373	Street Lighting Equipment	7,548,466.00	9.29%	701,252.49
		592,090,882.00	3.14%	18,615,564.52
	General			
389	Land	2,290,068.00	0.00%	0.00
390	Structures	38,285,680.00	2.92%	1,117,941.86
391	Office Furniture Equipment	4,495,803.00	4.21%	189,273.31
392	Transportation Equipment	1,504.00	0.00%	0.00
393	Stores Equipment	314,999.00	2.80%	8,819.97
394	Tools & Work Equipment	3,471,232.00	3.34%	115,939.15
395	Laboratory Equipment	399,653.00	4.11%	16,425.74
396	Power Operated Equipment	36,771.00	0.00% **(2)**	0.00
397	Communications Equipment	1,123,257.00	4.34%	48,749.35
398	Miscellaneous Equipment	537,228.00	3.18%	17,083.85
		50,956,195.00	2.97%	1,514,233.23
	Total Annual Depreciation Accrual	**655,947,473.00**	**3.46%**	**22,709,876.94**

Notes:

(1) The Depreciation Rates for Commonwealth Electric are based upon the rates last approved by the Department in DPU 90-331.

(2) The Depreciation rate approved by the Department was 7.51%, however the company has set the depreciation rate to zero to reflect that the investments are fully depreciated.

Cambridge Electric Light Company
Plant Balances as of 6/30/2005

Col. A	Col. B	Col. C	Col. D. Old	Col. E
	Intangibles	**Plant Balance**	**Depr. Rate (1)**	**Annual Accrual**
303	Computer Software	2,684,034.00	20.00%	536,806.80
	Distribution			
360	Land	237,789.00	0.00%	0.00
361	Structures	2,304,751.00	2.68%	61,767.33
362	Station Equipment	36,280,382.00	2.85%	1,033,990.89
364	Poles & Fixture	2,795,085.00	4.24%	118,511.60
365	Overhead Conductors	5,849,555.00	4.21%	246,266.27
366	Underground Conduit	19,963,364.00	2.27%	453,168.36
367	Underground Conductors	47,991,299.00	2.98%	1,430,140.71
368	Line Transformers	4,107,138.00	3.08%	126,499.85
369.1	Services -Overhead	1,769,862.00	6.38%	112,917.20
369.2	Services -Underground	4,258,606.00	2.71%	115,408.22
370	Meters	3,505,406.00	4.14%	145,123.81
373	Street Lighting Equipment	837,766.00	6.29% (2)	52,695.48
		129,901,003.00	3.00%	3,896,489.71
	General			
389	Land	290,820.00	0.00%	0.00
390	Structures	2,408,685.00	1.91%	46,005.88
391	Office Furniture Equipment	350,290.00	3.64%	12,750.56
392	Transportation Equipment	0.00	0.00%	0.00
393	Stores Equipment	18,308.00	4.53%	829.35
394	Tools & Work Equipment	15,643.00	3.73%	583.48
395	Laboratory Equipment	0.00	3.08%	0.00
396	Power Operated Equipment	0.00	3.51%	0.00
397	Communications Equipment	7,390.00	3.75%	277.13
398	Miscellaneous Equipment	31,231.00	3.65%	1,139.93
		3,122,367.00	1.97%	61,586.33
	Total Annual Depreciation Accrual	**135,707,404.00**	**3.31%**	**4,494,882.85**

Notes:

(1) The Depreciation Rates for Cambridge Electric Light Company are based upon the rates last approved by the Department in DPU 92-250.

(2) The Depreciation composite rate of 6.29 % for Streetlighting Equipment Account 373 was based on the weighting of the following sub-account rates, that Department approved during the 1992-1999 period, as applied to its corresponding plant balances in effect at year end 1997.

Sub-Account	Rate	1997 Plant Balances
373.71	7.27	2,643,000
373.73	5.90	62,000
373.74	3.24	478,000
373.75	3.73	432,000

Boston Edison Company
Plant Balances as of 6/30/2005

Col. A	Col. B	Col. C	Col. D. Old	Col. E
	Intangibles	**Plant Balance**	**Depr. Rate (1)**	**Annual Accrual**
303	Computer Software	15,866,267.00	20.00%	3,173,253.40
	Distribution			
360	Land	7,251,877.00	0.00%	0.00
361	Structures	55,628,598.00	2.98%	1,657,732.22
362	Station Equipment	304,209,888.00	2.98%	9,065,454.66
364	Poles & Fixture	82,628,049.00	2.98%	2,462,315.86
365	Overhead Conductors	233,951,891.00	2.98%	6,971,766.35
366	Underground Conduit	248,129,841.00	2.98%	7,394,269.26
367	Underground Conductors	750,352,352.00	2.98%	22,360,500.09
368	Line Transformers	278,541,472.00	2.98%	8,300,535.87
369	Services	163,376,051.00	2.98%	4,868,606.32
370	Meters	117,870,090.00	2.98%	3,512,528.68
373	Street Lighting Equipment	18,214,329.00	2.98%	542,787.00
		2,260,154,438.00	2.97%	67,136,496.32
	General			
389	Land	3,363,059.00	0.00%	0.00
390	Structures	50,973,478.00	4.03%	2,054,231.16
390	Leasehold Improvements	6,805,913.00	2.76% (2)	187,843.20
391	Office Furniture Equipment	9,746,868.00	4.03%	392,798.78
391	Office Equipment - Computers	5,897,214.00	20.00% (3)	1,179,442.80
392	Transportation Equipment	0.00	0.00%	0.00
393	Stores Equipment	1,114,273.00	4.03%	44,905.20
394	Tools & Work Equipment	4,208,475.00	4.03%	169,601.54
395	Laboratory Equipment	8,151,414.00	4.03%	328,501.98
396	Power Operated Equipment	0.00	4.03%	0.00
397	Communications Equipment	12,235,839.00	4.03%	493,104.31
398	Miscellaneous Equipment	398,926.00	4.03%	16,076.72
		102,895,459.00	4.73%	4,866,505.70
	Total Annual Depreciation Accrual	**2,378,916,164.00**	**3.16%**	**75,176,255.42**

Notes:

(1) The Depreciation Rates for Boston Edison are based upon the rates in the Settlement Agreement approved by the Department in DPU 92-92.

(2) The Depreciation rate for Leasehold Improvements are amortized based upon the period of related agreements per DPU 92-92.

(3) The Office Equipment-Computers are amortized over a life of 5 years per the DTE approved Settlement Agreement in DPU 92-92.

Total NSTAR Electric Company
Plant Balances as of 6/30/2005

Col. A	Col. B	Col. C	Col. D. Old	Col. E
	Combined Totals	**Plant Balance**	**Depr. Rate**	**Annual Accrual**
	Intangibles	31,450,697.00	20.00%	6,290,139.40
	Distribution	2,982,146,323.00	3.01%	89,648,550.55
	General	156,974,021.00	4.10%	6,442,325.26
	Total Annual Accrual	**3,170,571,041.00**	**3.23%**	**102,381,015.21**

NSTAR Electric
Plant Balances as of 6/30/2005

Col. A	Col. B	Col. C	Col. D. New	Col. E	Col. F Adj. New	Col. G
	Intangibles	**Plant Balance**	**Depr. Rate**	**Adj. Factor**	**Depr. Rate**	**Annual Accrual**
303	Computer Software	31,450,697	20.00%			6,290,139
	Distribution					
360	Land	10,378,193	0.00%	0.000000	0.0000%	0
361	Structures	59,548,406	1.92%	0.950162	1.8243%	1,086,348
362	Station Equipment	396,117,023	2.51%	0.950162	2.3849%	9,447,021
364	Poles & Fixture	188,453,704	3.28%	0.950162	3.1165%	5,873,219
365	Overhead Conductors	381,214,079	2.93%	0.950162	2.7840%	10,612,903
366	Underground Conduit	301,402,991	2.56%	0.950162	2.4324%	7,331,371
367	Underground Conductors	881,569,603	3.33%	0.950162	3.1640%	27,893,210
368	Line Transformers	370,629,167	3.60%	0.950162	3.4206%	12,677,679
369	Services - Overhead	73,583,145	2.54%	0.950162	2.4134%	1,775,864
369	Services - Underground	142,943,067	2.92%	0.950162	2.7745%	3,965,917
370	Meters	149,706,384	4.41%	0.950162	4.1902%	6,273,018
373	Street Lighting Equipment	26,600,561	10.73%	0.950162	10.1952%	2,711,991
		2,982,146,323	3.01%			89,648,541
	General					
389	Land	5,943,947	0.0000%		0.0000%	0
390	Structures	91,667,843	4.3600%	0.497437	2.1688%	1,988,116
390	Leasehold Improvements - Purdential	2,671,971	16.0600%	1.000000	16.0600%	429,119
390	Leasehold Improvements - Mass Av Garage	965,309	5.2200%	1.000000	5.2200%	50,389
390	Leasehold Improvements - Hyde Park Serv Ctr	587,974	4.6800%	1.000000	4.6800%	27,517
390	Leasehold Improvements - Walpole Serv Ctr	368,461	6.1500%	1.000000	6.1500%	22,660
390	Leasehold Improvements - Waltham Serv Ctr	1,959,710	6.9300%	1.000000	6.9300%	135,808
390	Leasehold Improvements - Other	252,489	0.0000%	1.000000	0.0000%	0
391	Office Furniture Equipment	14,592,961	15.2500%	0.497437	7.5859%	1,107,010
391	Office Equipment - Computers	5,897,214	9.9200%	0.497437	4.9346%	291,002
392	Transportation Equipment	1,504	0.0000%	0.497437	0.0000%	0
393	Stores Equipment	1,447,580	20.7300%	0.497437	10.3119%	149,273
394	Tools & Work Equipment	7,695,350	27.5100%	0.497437	13.6845%	1,053,070
395	Laboratory Equipment	8,551,067	13.6600%	0.497437	6.7950%	581,044
396	Power Operated Equipment	36,771	0.0000%	0.497437	0.0000%	0
397	Communications Equipment	13,366,486	8.5000%	0.497437	4.2282%	565,164
398	Miscellaneous Equipment	967,385	8.7600%	0.497437	4.3575%	42,154
		156,974,022	4.1041%			6,442,325
	Total Annual Depreciation Accrual	**3,170,571,042**	**3.2291%**			**102,381,006**

NSTAR Electric Company
Determination of Leasehold Improvements

	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J
Line		Original Cost	12/31/2005 Accumulated Depreciation	12/31/2005 Unrecoverd Cost	2006 Depreciation	12/31/2006 Unrecoverd Cost		Remaining years on Lease	Annual Accrual	Accrual Rate
1	Watertown	223,355.41	54,887.86	168,467.55	6,164.61	0.00	A	0.00	0.00	0.00%
2	General	3,760.31	1,731.08	2,029.23	103.78	0.00	A	0.00	0.00	0.00%
3	Summit	25,372.50	6,235.10	19,137.40	700.28	0.00	A	0.00	0.00	0.00%
4	Prudential	2,671,970.87	1,029,774.37	1,642,196.50	73,746.40	1,715,942.90	B	4.00	428,985.72	16.06%
5	Hyde Park	587,973.81	150,010.03	437,963.78	16,228.08	454,191.86	C	16.50	27,526.78	4.68%
6	Waltham	1,959,709.67	700,888.17	1,258,821.50	54,087.99	1,312,909.49	D	9.67	135,771.41	6.93%
7	Walpole	368,461.45	123,579.25	244,882.20	10,169.54	255,051.74	E	11.25	22,671.27	6.15%
8	Mass Av Garage	965,309.07	462,741.96	502,567.11	26,642.53	529,209.64	F	10.50	50,400.92	5.22%
9		6,805,913.09	2,529,847.82	4,276,065.27	187,843.20	4,267,305.62			665,356.09	9.78%